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BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE STATE OF CALIFORNIA

Application of Pacific Gas and Electric Company Proposing Cost of Service and Rates for Gas Transmission and Storage Services for the Period 2015-2017.	Application 13-12-012 (Filed December 19, 2013)
And Related Matter.	Investigation 14-06-016

NOTICE OF EX PARTE COMMUNICATIONS

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Dated: May 27, 2016

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NOTICE OF EX PARTE COMMUNICATIONS

In compliance with the provisions of Article 8 and Rule 8.2 of the Commission's Rules of Practice and Procedure, Dynegy Inc. (Dynegy) submits this notice of ex parte communications.

The communications occurred on May 24, 2016, at the Commission's offices in San Francisco. Alan Padgett, Vice President, GasCo Asset Management for Dynegy; and Brian Cragg and Suzy Hong, outside counsel for Dynegy, met with Christine Hammond, Ken Koss, and Scott Murtishaw, advisors to President Picker, at 3:00 p.m. and with Rachel Peterson, Chief of Staff for Commissioner Randolph, at 4:00 p.m. Each meeting lasted about 30 minutes.

At the meetings, Mr. Padgett and Mr. Cragg discussed the following points:

- The unique history of Units 1 and 2 of the Moss Landing Power Plant in the context of this proceeding.

- The history of the Gas Accord III, IV, and V settlements, and how Commission approval of those settlements does not require continuation of a particular rate design.
- The Commission is not required to adopt a permanent rate design in this proceeding, but may instead adopt a rate design more suitable to the extraordinary circumstances of this case and the unprecedented rate increases necessitated by the investments in pipeline safety proposed by Pacific Gas & Electric Company (PG&E).
- The 155% rate increase faced by electric generation customers served by the Local Transmission system (EG-AOC customers under PG&E's Schedule G-EG) under the Proposed Decision Authorizing Pacific Gas and Electric Company's Revenue Requirement for 2015-2017 for Gas Transmission and Storage Services (PD).
- The historical differential between rates for electric generation customers served by the Backbone system (EG-BB customers under PG&E's Schedule G-EG) and EG-AOC customers of about 15 cents/Dth compared to: (i) PG&E's original proposal for an 88 cent/Dth differential between the two tiers of EG rates, and (ii) the PD's proposed rate differential of 81.0 cents/Dth for 2016, which would amount to a differential of 77.2 cents/Dth for 2016 even after taking into consideration the $850 million PG&E shareholder penalty required to be contributed toward investments in pipeline safety.

- That even for efficient generators like Moss Landing 1 & 2, a 77.2-cent differential would increase costs and result in significant increases in bids in electric markets, as well as create other planning and operational concerns for the units.
- PG&E's capital investments in facilities located on the Local Transmission system respond to a demand for increased safety, and are not caused by an increase in demand for gas service.
- The PD relies on a misplaced concept of cost-causation that is not applicable to the extraordinary circumstances surrounding the need for PG&E's capital investments in the Local Transmission system, as a result the PD adopts an erroneous cost allocation that allocates the bulk of the costs of PG&E's proposed pipeline safety investments to EG customers served by the Local Transmission system.
- The PD's cost allocation approach combined with the two-tiered rate design largely excuses Backbone electric generation customers from making any contribution to the bulk of the safety investments PG&E is proposing. It is inequitable to excuse one group of customers from sharing the costs of investments needed to ensure a safe gas transportation system. Safety is a system-wide obligation.
- The PD would have the counter-productive result of decreasing the contribution that Moss Landing 1 & 2 would make to the Local Transmission revenue requirement. PG&E's modeling predicts that if PG&E's proposed rates and rate structure are adopted, Moss Landing 1 &

2, which are efficient, 21st Century facilities, would operate at a 1% capacity factor, far below the roughly 50% capacity factor the units have maintained in recent years. At a 1% capacity factor, the contribution these units would make to the Local Transmission revenue requirement would drop from around \$4 million to \$8 million in recent years to less than \$600,000 annually. The resulting shortfall, under PG&E's proposals, would have to be made up by Local Transmission customers, further worsening the differential between Local Transmission and Backbone electric generation customers.

- Under PG&E's proposals, generators on the Local Transmission system might be displaced by less efficient generators on the Backbone system, resulting in greater greenhouse gas emissions and higher freshwater consumption.
- Amortization of the balance in the Gas Transmission and Storage Memorandum Account over a period of 18 months, as proposed in the PD, will only serve to exacerbate: (i) the already enormous rate increase for EG-AOC customers; and (ii) the differential between the rates for EG-BB and EG-AOC customers.
- The Commission has wide discretion to fashion a rate design that will accommodate the extraordinary safety-related capital expenditures that the PD approves without disproportionately burdening any particular customer groups.

Written materials used in the meetings included (1) Dynegy's opening brief; and (2) Dynegy's reply brief. Copies of these documents are attached to this notice.

Respectfully submitted May 27, 2016, at San Francisco, California.

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ATTACHMENT 1

BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE STATE OF CALIFORNIA

Application of Pacific Gas and Electric Company Proposing Cost of Service and Rates for Gas Transmission and Storage Services for the Period 2015-2017 (U39G).	Application 13-12-012 (Filed December 19, 2013)
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OPENING BRIEF OF DYNEGY INC.

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Dated: April 29, 2015

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SUMMARY OF RECOMMENDATIONS

In this brief, Dynegy Inc. addresses the rate structure for electric generation (EG) customers who receive gas transportation services under PG&E's Schedule G-EG. Dynegy recommends:

1. The Commission should adopt a single EG rate for all customers served under Schedule G-EG. The single rate will eliminate the competitive distortions of the bifurcated rate structure of Schedule G-EG while providing a solid revenue base for the safety improvement projects the Commission determines are needed.
2. If the Commission is reluctant to adopt a single EG rate, the Commission should direct PG&E to enter into a contract with Dynegy under which PG&E would provide gas transportation services to Moss Landing Units 1 & 2 at a price set at 10 cents/Dth above the Backbone-level rate for the period in question. In addition, Dynegy would guarantee a minimum payment of $100,000 per month for gas transmission services for Moss Landing Units 1 & 2.

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OPENING BRIEF OF DYNEGY INC.

Nearly 45 years ago, the California Supreme Court instructed the Commission on its obligation to consider the competitive implications of every decision it makes. In the decision reviewed in *Northern California Power Agency v. Public Utilities Commission* (1971) 5 Cal.3d 370 (*NCPA*), the Commission had decided that there was "no need to address" the competitive issues raised in the case it was considering. The California Supreme Court disagreed and annulled the Commission's decision for failing to consider the antitrust implications of its decision. The Court went on to say that even if no party had raised the competitive issues, "The Commission may and should consider *sua sponte* every element of public interest affected by facilities which it is called upon to approve."[1]

This proceeding has competitive implications that go well beyond the usual rote calculations that are the primary topics in other rate cases. Dynegy Inc. (Dynegy), the owner and operator of the Moss Landing Power Plant, has actively participated in this proceeding because

[1] *NCPA* at 380.

of the competitive implications of the proposals presented by Pacific Gas and Electric Company (PG&E). PG&E's proposals, if adopted by the Commission, would have significant implications for competition in California's electricity markets and for the achievement of the Commission's goal of a safe gas transportation system.

The effect of PG&E's proposals on competition has two primary strands.

First, PG&E's proposals will increasingly discriminate among competing electric generation (EG) customers who receive gas transportation service under PG&E's Schedule G-EG. Specifically, PG&E proposes a *102% rate increase* for noncore electric generation customers served by gas pipelines classified as part of the local transmission system (including the Moss Landing plant), while PG&E proposes a 23% rate *decrease* for noncore electric generation customers served by pipelines classified as part of the backbone system.[2] Noncore electric generators, whether served by the local transmission or backbone system, compete in the same wholesale electric markets, and the disparate rate treatment PG&E proposes—a difference of 88 cents per decatherm (Dth)—is likely to distort that competition and affect the dispatch of electric generation units by the California Independent System Operator (CAISO). In *NCPA*, the California Supreme Court reminded the Commission of its obligation to consider the effects on competition of its decisions.[3]

Second, the magnitude of PG&E's requested increase in rates for gas transportation services is enormous, with some customers, including the Moss Landing plant, facing rate increases of over 100%. Dynegy appreciates the need to ensure that PG&E's gas transportation system is safe, and Dynegy supports the Commission's efforts to improve the

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[2] Exh. PG&E-2, p. 17-11, Table 17-5.

[3] *See also Industrial Communications Systems, Inc. v. Public Utilities Com.* (1978) 22 Cal.3d 572, where the California Supreme Court annulled the Commission's decisions because the Commission "did not consider and make findings on the anticompetitive effect" of a regional plan agreed to between telephone utilities (22 Cal.3d at 583).

safety of PG&E's gas transportation system. However, placing the bulk of the burden of constructing and maintaining a safe gas transmission system on one group of customers, resulting in a rate increase that is over five time larger than the level of increase the Commission has defined as rate shock, seems neither just nor reasonable. Dynegy has paid PG&E millions of dollars in gas transportation rates in recent years, some portion of which was presumably to be used to ensure the safety of PG&E's gas transportation system. Despite these significant contributions, PG&E is now seeking over four billion dollars in revenues, much of which is proposed to cover the cost of investments that PG&E says are required for a safe gas transportation system. The sheer size of PG&E's requested rate increase raises the suspicion that PG&E is trying to make up for years of neglect and deferred maintenance on its gas transportation system in a single rate case cycle. The Commission should not allow PG&E to use the Commission's concern about safety as leverage for approval of projects that are not central to the safe operation of the pipeline system and that result in rate increases that alter the competitive landscape for electricity. The Commission should be guided by its obligation under Public Utilities Code sections 451 and 454 to authorize only rates that are just and reasonable.

To the extent that the Commission determines that PG&E's requested projects and investments are needed for safe operation of the gas transmission system, the huge financial burden of those investment should be shared by all customer classes. PG&E proposes to concentrate the cost of the necessary investments in safety on customers served by the local transmission system, and in particular on the All Other Customers group of Schedule G-EG, which is faced with a 102% rate increase under PG&E's proposals. <u>**All**</u> customers benefit from the safe operation of the gas transmission system, and the costs of a safe gas transmission system should accordingly be borne by all customers.

PG&E's proposals have an internal inconsistency. Increasing the differential between backbone and local transmission rates for EG rates to 88 cents/Dth will make it nearly impossible for EG customers paying the All Other Customers rate to compete in electricity markets, which means that they will **not** be using gas transportation services and will **not** be paying PG&E for those services. These are the same customers, however, that PG&E expects to bear the lion's share of the cost of the pipeline safety improvement projects PG&E proposes.

Dynegy will elaborate on these concerns in this brief, submitted in compliance with Rule 75 of the Commission's Rules of Practice and Procedure and the schedule established by Administrative Law Judge Amy Yip-Kikugawa. Dynegy will follow the common briefing outline but has modified the format and font in certain sections for clarity. Dynegy has no comments on some sections of the common briefing outline, and those sections will be briefly identified. Dynegy reserves the right to address these topics in its reply brief in response to the arguments and statements of other parties in their opening briefs.

EXECUTIVE SUMMARY

The 2005 bifurcation of the rates electric generators pay for gas transmission service is having expected and unexpected consequences that threaten the commercial viability of electric generators that are connected to pipelines classified as part of the local transmission system. As expected, the economic incentives created by the creation of two rate levels for generators served under Schedule G-EG have encouraged new generation projects to connect directly to pipelines classified as part of the backbone transmission system.[4] The San Bruno explosion, however, highlighted the need for billions of dollars in upgrades to ensure the safety of the gas transmission system. Many of these pipeline safety improvement projects are

[4] At least since 2011, "the large electric generators that have connected to the PG&E system . . . have all been connected to the backbone." Reporter's Transcript (RT) 3146 (Christopher/PG&E).

proposed to be added as part of the local transmission system, and under PG&E's standard ratemaking approach, those costs would be allocated to customers using the local transmission system, resulting in PG&E's proposal to increase rates for local transmission level electric generators by over 100%. The resulting rate ensures that, according to PG&E's own analysis, many local transmission generators will be unable to compete in electricity markets at commercially sustainable levels, and as a result will make little or no contribution to the huge local transmission revenue requirement PG&E is requesting.

The 2005 rate bifurcation excused electric generation customers on the backbone system from making any contribution to the costs of the local transmission system, Without any contribution from the backbone EG customers, PG&E's local transmission rates are poised to initiate a death spiral, where increasing rates lead to lower revenues because of customers' inability to compete, lower revenues lead to higher rates as costs are spread among decreasing Dth of throughput, higher rates lead to fewer customers and lower throughput, and the cycle continues.

In this brief, Dynegy, the owner of Moss Landing Units 1 & 2, which were put into an unfavorable competitive position by a change in rate structure implemented just 30 months after the units began commercial operation, discusses the origin of bifurcated rates for electric generators, the effects of those rates on competition in the electric industry, the exacerbation of competitive distortions by PG&E's current proposal for rate and rate structures, and the potential solutions for the challenges confronting the Commission.

1. <u>Overview</u>

1.1 Legal Issues

The primary legal issue confronting the Commission in this proceeding is its obligation to consider the competitive implications of its decision, as noted in the introduction.

While rate cases ordinarily concern only the determination of just and reasonable rates for a regulated monopoly, some of the proposals in this rate case would have significant effects in competitive markets for electricity. The Commission has previously recognized the basic competitive concern raised by the adoption of a two-level rate for EG customers who receive transportation services under Schedule G-EG in a previous (and unsuccessful) request for a backbone-level rate:

> The relief requested [a backbone-level rate] would provide more favorable treatment to specific merchant power plants that would obtain *a distinct competitive advantage* over other merchant generators in California by avoiding payment of local transmission charges which all other on-system merchant generators pay.[5]

PG&E's proposal in this proceeding goes well beyond this basic competitive concern. PG&E's proposed rate structure for EG customers, combined with the huge proposed differential between rates for EG customers served by the local transmission system and rates for EG customers served by the backbone system, would unduly favor the generators receiving backbone-level rates over generators served by the local transmission system in their competition to sell their output in electricity markets and, according to PG&E's own studies, would reduce generation from Moss Landing Units 1 & 2 to insignificant levels.

1.2 Policy Issues

The policy issues confronting the Commission in this proceeding include:

- Whether the Commission should expressly consider the effect of gas transportation rates on the market for electricity
- Whether the unique history of Moss Landing Units 1 & 2 warrants an accommodation designed to allow Units 1 & 2 a reasonable opportunity to compete in electric markets

[5] Decision (D.) 01-05-086, Exh. Dynegy-3, p. 13 (emphasis added).

- Whether gas throughput and revenue forecasts should be adjusted to reflect the fact that EG customers pay transportation rates only when they are operating; if gas transportation rates are too high, EG customers will not be dispatched and PG&E will receive no revenues

These policy issues interact in a complex manner. As discussed in more detail later in this brief, the restructuring of gas transportation rates for EG customers that was part of Gas Accord III bifurcated the electric generation customer class and developed a two-level rate structure. Starting in 2005, EG customers that were connected to pipelines classified as part of the backbone system and who met other eligibility requirements were served under the Backbone-level rate, and those who were served by pipelines classified as part of the local transmission system were served under the All Other Customers rate of Schedule G-EG. PG&E has proposed in this proceeding to increase the All Other Customers rate by 102%, while lowering the Backbone-level rate by 23%. But because generators compete in the same CAISO markets, the resulting 88-cent/Dth rate differential will make it far more difficult for EG customers served by the local transmission system to compete. In fact, PG&E projects that under its proposal, the annual capacity factor for Moss Landing Units 1 & 2 will drop to 1%, far below the units' historical level of generation.

As a result of this rate differential, the CAISO's dispatch of generation will shift to the units connected to the backbone system. Even without any physical bypass of the local transmission system, there is in effect a commercial bypass as dispatch migrates to the units connected to the backbone system. As dispatch shifts to the units paying the Backbone-level rate, however, market-sensitive generation units paying the All Other Customers rate will see revenues dry up, and eventually these facilities will either go out of business or rely on revenues from tolling agreements or similar non-market mechanisms. The shift of generation to the backbone may have effects on congestion and the transmission system,[6] but a more immediate and pertinent effect is that the revenues that PG&E relies on to cover the costs of the local transmission system will diminish. Under PG&E's proposal, EG customers who are eligible for the Backbone-level rate contribute **nothing** toward the cost of the local transmission system, while customers paying the All Other Customers rate pay 88 cents/Dth toward local transmission costs.[7] If EG customers paying the All Other Customers rate are not dispatched because their costs are higher than EG customers on the backbone system, the revenues that PG&E is counting on to cover local transmission costs will not materialize.

Under PG&E's proposal, this rate case cycle is a particularly bad time to experience a shortfall in local transmission revenues. Much of the over $4 billion that PG&E requests in its application is designated for projects intended to improve the safety of PG&E's transmission system, and many of those projects are located on the local transmission system. PG&E has proposed to allocate the costs of those local transmission projects to customers who use the local transmission system, which is why the All Other Customers rate of Schedule G-EG is proposed to increase by 102%. If a shortfall in revenues results from the fact that EG customers on the local transmission system are not being dispatched and thus are not transporting gas and not paying PG&E for gas transportation services, PG&E will either have to turn to other customers to make up the shortfall or defer or cancel projects that it has determined are necessary for the safety of the gas transmission system. In addition, as dispatch shifts to units paying the Backbone-only rate, the shortfall in local transmission revenues will become more severe, because electricity that was previously produced by generators who pay rates that include a

[6] Exh. Dynegy-1, p. 34,

[7] Exh. PG&E-2, p. 17AtchA-4, Table 17-D.

contribution the local transmission revenue requirement (*i.e.,* the All Other Customers rate) will now be produced by generators who pay rates that make no contribution to the local transmission revenue requirement (*i.e.,* the Backbone-level rate).

The competitive impacts of PG&E's proposal will have industry-wide repercussions, but Moss Landing Units 1 & 2 may be particularly hard-hit. Some generators connected to the local transmission system have long-term tolling agreements or other contracts that in effect insulate them from the competitive effects of PG&E's proposal, at least until the agreements expire.[8] Other generators connected to the local transmission system, including those represented by the Northern California Generation Coalition, are owned and operated by publicly owned utilities and irrigation districts, and their output is primarily intended for the consumption of the customers of these entities. Higher gas transportation rates may affect the rates their electric customers pay, but these plants have captive electric customers who can backstop the investment in the plant even if the plants are dispatched much less due to higher gas transportation costs.

Moss Landing Units 1 & 2, which began operation 30 months before the change in gas transmission rate structure, are not owned by a publicly owned or investor-owned utility, and they do not have long-term agreements to insulate them from the higher rates PG&E proposes. Moss Landing Units 1 & 2 must compete in the CAISO's markets to earn revenues, and if they are not successful in that competition, then they are not dispatched, they don't run, they don't earn any revenues, they don't pay PG&E for gas transportation, and they make no contribution to the costs of the local transmission system.

Moss Landing Units 1 & 2, then, are forerunners for other EG customers on the local transmission system and are harbingers of the effects that other generators will see over the

[8] See, *e.g.,* D.09-04-010, D.10-07-042.

next few years. The Commission's resolution of the policy issues raised in this proceeding and its treatment of Moss Landing Units 1 & 2 will significantly shape the future electricity industry in California and affect PG&E's ability to construct and maintain a safe gas transmission system.

1.3 Summary of Revenue Requirement Recommendations

Dynegy has no comments on this issue at this time.

2. Safety and Risk Management Issues

Dynegy has no comments on this issue at this time.

3. Potential Shareholder Cost Responsibility Issues

In D.15-04-024, the Commission ordered that $850 million of the costs of projects for pipeline safety improvement would be funded by shareholders, rather than ratepayers. The Commission further ruled, "Only costs that PG&E would have been granted rate recovery for in the GT&S [this proceeding] - but for this decision - will count towards the $850 million."[9] To the extent that the Commission decides as part of this proceeding that the cost of certain pipeline safety improvement projects would have been authorized for recovery in rates, Dynegy urges that the funding of those projects should come from shareholders and the revenue requirement associated with those projects should be removed from the rates authorized in this proceeding. Because of the magnitude of the rate increase PG&E proposed for the All Other Customers rate under Schedule G-EG, Dynegy urges that any shareholder funding should first be allocated to offset the costs of pipeline safety improvement projects on the local transmission system.

4. Impact of Proposals on Customers

Dynegy has no comments on this issue at this time.

5. Ratemaking Issues

Dynegy has no comments on this issue at this time.

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[9] D.15-04-024, p. 93.

6. 2011-2014 Capital Expenditures

Dynegy has no comments on this issue at this time.

7. Transmission Pipe

Dynegy has no comments on this issue at this time.

8. Storage

Dynegy has no comments on this issue at this time.

9. Facilities

Dynegy has no comments on this issue at this time.

10. Corrosion Control

Dynegy has no comments on this issue at this time.

11. Gas Transmission System Operations and Maintenance Activities

Dynegy has no comments on this issue at this time.

12. Other GT&S Support Plans

Dynegy has no comments on this issue at this time.

13. Gas System Operations

Dynegy has no comments on this issue at this time.

14. Information Technology

Dynegy has no comments on this issue at this time.

15. Reporting Requirements and Program Management

Dynegy has no comments on this issue at this time.

16. Revenue Requirement Issues

Dynegy has no comments on this issue at this time.

17. Rate Issues

17.1 Throughput Forecasts

Dynegy has no comments on this issue at this time.

17.2 Cost Allocation and Rate Design

17.2.1 Backbone Rate Design

Dynegy has no comments on this issue at this time.

17.2.2 Local Transmission Cost Allocation

Dynegy has no comments on this issue at this time.

17.2.3 Storage Rate Design

Dynegy has no comments on this issue at this time.

17.2.4 Transmission Level Customer Access Charges

Dynegy has no comments on this issue at this time.

17.2.5 <u>ELECTRIC GENERATION RATE DESIGN</u>

Dynegy, as the owner and operator of the Moss Landing Power Plant and the now-closed Morro Bay Power Plant, has historically been one of the largest gas transportation customers of PG&E. Since it acquired its Northern California generating assets in 2007, Dynegy has participated in PG&E's gas transmission and storage cases and Gas Accord settlements out of a concern for what the Commission has called the "convergence between the natural gas and electricity industries,"[10] referring to the rise of competitive mechanisms in what had once been closely regulated industries and the effect of natural gas prices on electricity prices.

Dynegy's concern in these cases has been the effect of gas transportation rates and rate structures on competition in the electricity industry and in particular how the split of rates for gas transmission services to electric generation customers affects the ability of Moss Landing Units 1 & 2 to compete with comparable combined cycle units that have the rate advantage of being connected directly to PG&E's backbone transmission system.

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[10] D.00-04-060, slip op. p. 50.

In the following sections, Dynegy will present a brief history of the two-level rate structure for Schedule G-EG and explain how that structure influences the ability of Moss Landing Units 1 & 2 to compete in the markets for electricity conducted by the CAISO. This history is critical to an understanding of why equity requires an accommodation in light of the unique circumstances of the development and operation of Units 1 & 2. Beyond the unique circumstances of Moss Landing Units 1 & 2, however, Dynegy is concerned more generally about how the two-level gas transportation rate of Schedule G-EG interacts with PG&E's proposed doubling of rates for some EG customers to quash and perhaps to eliminate the ability of generating plants served through PG&E's local transmission system to compete in electricity markets, to the considerable detriment of PG&E's remaining gas transportation customers. That concern leads to a discussion of why arguments in support of PG&E's proposed gas transportation rates and rate structure for EG customers are unavailing, followed by an evaluation of potential mechanisms to address the anticompetitive elements of PG&E's proposal.

17.2.5.1 Background

Units 1 & 2 of the Moss Landing Power Plant are gas-fired combined cycle units with a total capacity of 1020 MW.[11] Units 1 & 2 replaced the previous Units 1-5 at the Moss Landing site, with a total capacity of 613 MW, which PG&E constructed in the 1950s and shut down in 1995.[12] Duke Energy, the developer of Units 1 & 2, filed the Application for Certificate (AFC) for Units 1& 2 of the Moss Landing Power Plant at the California Energy Commission (CEC) on May 7, 1999.[13] The CEC approved the application and granted the certificate on

[11] Exh. Dynegy-1, p. 6. The certification by the California Energy Commission lists the capacity of Units 1 & 2 as 1060 MW.
[12] Exh. Dynegy-2, p. 14.
[13] Exh. Dynegy-2, p. 7.

October 25, 2000,[14] and construction on Units 1 & 2 started on November 28, 2000. Units 1 & 2 went on line on July 1, 2002.[15]

The planning and investment in Units 1 & 2 spanned the worst days of the California Energy Crisis. At a time when investment in electric generation in California was considered as risky as investment in a third-world country, Units 1 & 2 were the manifestation of an investment of nearly half a billion dollars in new, efficient gas-fired generation.

17.2.5.1.1 Gas Accord I Required All Transmission-Level Customers to Pay Local Transmission Rates and Contribute to the Cost of the Local Transmission System

At the time Units 1 + 2 were being planned and constructed, the structure of gas transportation rates for electric generation customers was governed by the first Gas Accord.[16] Gas Accord I unbundled transmission system service (consisting of transportation provided over the backbone and local transmission systems) from distribution service. Consistent with previous cases in which the Commission had considered (but not adopted) proposals for a backbone-level rate, Gas Accord I did not adopt a backbone-level rate but instead required all on-system end-users, including EG customers, to pay both backbone transmission charges and local transmission charges.[17] Under Gas Accord I, all electric generation customers of PG&E paid the same gas transportation rate, which included a contribution toward the costs of the local transmission system.[18]

Because Moss Landing Units 1 & 2 were built on a brownfield site that had been occupied by aging PG&E generating units, gas to the new Units 1 and 2 was provided over

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[14] Exh. Dynegy-2.
[15] Exh, Dynegy-1, p. 6.
[16] Gas Accord I, Appendix B to D.97-08-055.
[17] Gas Accord I, Appendix B to D.97-08-055, §§ II.E.14.b, II.H.1.e.
[18] Exh. Dynegy-1, pp. 6, 7; Gas Accord I, Appendix B to D.97-08-055, §§ II.E.14.b, II.H.1.e.

PG&E's existing Line 301-G, which had previously served the retired PG&E units.[19] A second gas pipeline, Line 301-A, continued to serve Units 6 and 7, which remained in operation after the transfer of ownership of the plant from PG&E.

17.2.5.1.2 The Gas Accord II Proceeding Continued the Provisions of Gas Accord I and Adopted a New Rate Structure for Electric Generation Customers

PG&E filed an application proposing a new market structure for the natural gas industry in Northern California in October 2001.[20] As part of that application, PG&E requested a two-year continuation of the provisions of Gas Accord I to allow for the resolution of PG&E's bankruptcy.[21] A settlement referred to as Gas Accord II, which extended the transmission market structure and rates agreed to in Gas Accord I for one year, to the end of 2003, was approved in D.02-08-070. Later in that same proceeding, the Commission considered and addressed proposals for restructuring gas transportation rates for EG customers.

In December 2003, 18 months **after** Units 1 and 2 began operation, the Commission, on a narrow vote in a hotly contested proceeding, decided to institute a new structure for gas transmission rates.[22] In D.03-12-061, the Commission addressed the market structure, rates, tariffs and terms and conditions of PG&E's gas transportation and storage services after the expiration of the extension agreed to in Gas Accord II at the end of 2003. In that decision, the Commission stated that it supported a backbone-level rate, and it provided some criteria for eligibility for backbone-level service. However, the Commission also concluded that it could not adopt any of the backbone rate proposals presented to it at that time. The Commission ordered PG&E "to submit a rate design . . . that represents a backbone level

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[19] Exh. Dynegy-1, pp. 6-7; see Exh. Dynegy-2, p. 14.
[20] Application 01-10-011.
[21] D.03-12-061, p. 2; Exh. Dynegy-4, Proposed Decision of ALJ Wong, November 18, 2003, p. 2.
[22] Exh. Dynegy-1, p. 7.

rate to be applied only to new load or incremental load that has been developed since March 1998."[23] Until that rate was proposed and approved, the then-existing rate structure (*i.e.,* all transmission-level customers would pay both a backbone and local transmission rate component) would continue in 2004.[24]

D.03-12-061 was subject to both applications for rehearing and petitions for modification. In response to the applications for rehearing, the Commission in D.04-05-061 deleted its discussion of the backbone-only rate and replaced this discussion with a substantially modified discussion. The Commission acknowledged that the eligibility requirements for backbone-level service in D.03-12-061 were unclear but stated, "Rather than attempting to clarify these requirements in the instant decision, we have decided to address these eligibility issues in PG&E's application to implement rates pursuant to this decision (A.04-03-021),"[25] an application that resulted in Gas Accord III.

17.2.5.1.3 Gas Accord III Developed a Two-Level Rate for Electric Generation Customers

The proceeding referred to in the decision modifying D.03-12-061 (A.04-03-021) resulted in a settlement, Gas Accord III, that the Commission approved in D.04-12-050.

In approving the Gas Accord III settlement, the Commission for the first time implemented a separate transportation rate for backbone-level service and exempted qualifying end-use customers from responsibility for local transmission charges.[26] The Commission decided to create two separate categories of electric generators. Generators who met certain eligibility requirements and who were served directly from pipelines classified as part of the

[23] D.03-12-061, p. 348 (deleted and replaced in D.04-05-061, p. 22).
[24] D.03-12-061, p. 348 (deleted and replaced in D.04-05-061, p. 22).
[25] D.04-05-061, pp. 9-10.
[26] Customers taking service under Schedule G-EG also pay a customer access charge and may be subject to a franchise fee surcharge and charges associated with public purpose programs.

backbone system (identified as Backbone Level End-Use Customers in Schedule G-EG) would be excused from making any contribution to the costs of the local transmission system, while generators who did not meet the eligibility requirements or who were served from pipelines classified as part of the local transmission system (identified as All Other Customers in Schedule G-EG) would continue to be required to contribute to the costs of the local transmission system.

Although the Commission in Gas Accord III did not adopt specific Backbone-level and All Other Customers rates, the announced change in the gas transportation rate structure for electric generators created an immediate competitive concern for Moss Landing Units 1 & 2. If Units 1 & 2 did not qualify for the Backbone-only rate (because the units were connected to PG&E's local transmission system), the newly bifurcated rate structure meant that Units 1 & 2 would face higher gas transportation rates than some of their main competitors in electricity markets who could qualify for the Backbone-level rate.[27] The differential in rates put Units 1 & 2 at a distinct disadvantage in relation to backbone-level generators who competed in the same markets. As a general matter, generating units with higher costs would have to submit higher bids in those markets if they hoped to cover their costs. But the higher transportation rates and resulting higher costs meant that generators not qualifying for the Backbone-level rate would be dispatched less than they had been historically, and the revenues from this reduced output would also decline.

A longer-term effect was that excusing backbone-level customers from making any contribution to the costs of the local transmission system left fewer customers to bear those costs and fewer units of gas throughput over which to spread those costs. A price spiral was initiated, in which increased rates led to higher bids, which led to lower throughput, which

[27] Exh. Dynegy-1, p. 7.

required that lower throughput to bear the undiminished costs of the local transmission system, leading to higher rates and the next iteration of the cycle.

Gas Accord III included agreed-on eligibility criteria for backbone-level service that were based on the testimony PG&E presented in A.04-03-021. These criteria were to be in effect for the term of the settlement, through December 31, 2007.[28] In summary, the criteria for backbone-level service for the term of Gas Accord III were:

- The load must be new or incremental to PG&E's system on or after March 1, 1998
- The load must never have been physically connected to PG&E's local transmission system
- The lateral connecting the customer to the backbone system must be either 100% owned by the customer or its affiliate or owned by PG&E but paid for in advance by the customer

These criteria presented a dilemma for Moss Landing Units 1 & 2. Although the new Units 1 & 2 were added to the PG&E system after March 1998, the units had logically and efficiently made use of and been physically connected to the existing pipelines serving the site, which were classified as part of PG&E's local transmission system. In addition, constructing a new lateral in an attempt to qualify Units 1 & 2 for backbone-level service would result in a redundant pipeline and create excess capacity and additional costs for PG&E and its customers. On the other hand, an inability to meet the eligibility requirements for backbone-level service would put Moss Landing Units 1 & 2 at a considerable economic disadvantage in relation to their

[28] D.04-12-050, Attachment A, §§ 3.2, 3.2.1.

competitors who could qualify for backbone-level service.[29] After an investment of half a billion dollars in new, efficient generation at a time when California was desperate for new generating capacity, Units 1 & 2 would be put at a significant competitive disadvantage by the radically changed EG rate structure.

The parties to Gas Accord III agreed that Units 1 & 2 would receive a $2 million annual bill credit to help mitigate the economic impact of the implementation of backbone-level service. The Commission, noting that Units 1 & 2 had begun operation in 2002 and that the Moss Landing power plant contributed over $5 million per year toward the local transmission revenue requirement,[30] approved this compromise and concluded that the bill credit for Units 1 & 2 "is reasonable and consistent with past Commission practice."[31] The Commission also acknowledged in another decision that "parties are free to address the eligibility criteria for backbone-level service in PG&E's February 9, 2007 application regarding its gas market structure and gas transmission and storage rates [the Gas Accord IV application]."[32]

17.2.5.1.4 Gas Accord IV Continued the Bill Credit

The Gas Accord IV settlement, approved in D.07-09-045, continued the $2 million annual bill credit for Moss Landing Units 1 & 2 through 2010 and added an annual escalator.[33] Gas Accord IV also provided for a $200,000 bill credit to be split among for four plants operated by members of the Northern California Generation Coalition (NCGC).[34] Under Gas Accord IV, the eligibility requirements for Backbone Level End-Use Service agreed to in Gas Accord III would continue through December 31, 2010 for transmission services, with some

[29] Exh. Dynegy-1, p. 8.
[30] D.04-12-050, pp. 14-15, 16.
[31] D.04-12-050, p. 24 (Conclusion of Law No. 6).
[32] D.05-06-042, p. 6 fn.3.
[33] D.07-09-045, Attachment A, § 8.5.
[34] D.07-09-045, Attachment A, § 8.5.

modifications. One of the modifications gave Units 1 & 2 the opportunity to qualify for backbone level service by exempting Units 1 & 2 from the requirement that a backbone level customer must **never** have been physically connected to PG&E's local transmission or distribution system.[35] In other words, Units 1 & 2 could qualify for backbone-level service if a lateral to the backbone system was constructed during the Gas Accord IV settlement period.

For the reasons discussed in section 17.2.5.3.6, below, Dynegy determined that building a third gas pipeline to the Moss Landing plant did not make sense from a physical or economic perspective.

17.2.5.1.5 Gas Accord V Continued and Escalated the Bill Credit for Units 1 & 2, but PSEP Cost Recovery Exacerbated the Gap Between the Two EG Rate Levels

In Gas Accord V, which the Commission approved in D.11-04-031, the parties agreed to continue the bill credit for Moss Landing Units 1 & 2 at an increased level of $2.5 million per year, with annual escalations, through the end of 2014.[36]

In late 2012, however, the Commission allowed PG&E to recover $299 million of the costs of its post-San Bruno Pipeline Safety Enhancement Plan (PSEP) from customers in 2012 through 2014.[37] The allocation of PSEP costs greatly increased the differential between Backbone-level and All Other Customers rates under Schedule G-EG, and as a result, until the PSEP rate increase expired at the end of 2014, Moss Landing Units 1 & 2 faced a considerable challenge as they attempted to compete in electric markets against their rivals who enjoyed significantly lower gas transportation rates. Units 1 & 2 were able to survive the PSEP increase in large part because there was little hydroelectric power available during these drought years, and gas-fired units were called on to make up the shortfall. In addition, Unit 2 of the San Onofre

[35] D.07-09-045, Attachment A, § 3.4.2.
[36] D.11-04-031, Appendix A, § 9.5.1.
[37] D.12-12-030, pp. 3, 126 (Ordering Paragraph No. 2).

Nuclear Generating Station (SONGS) shut down for refueling in early January 2012, and on January 31, 2012, Unit 3 shut down because of a small radiation leak. The SONGS units never restarted and have now been permanently retired. The absence of generation from SONGS during this period also increased the demand for gas-fired generation. SONGS will not return to service, but new capacity is being procured to make up for its retirement. Similarly, the drought will end at some point. The circumstances that created increased demand for gas-fired generation since 2012 will not persist.

That brief history brings us to 2015 and PG&E's current proposal for rates for service under Schedule G-EG. As explained in the following section, the end of the PSEP collection at the end of 2014 did not ensure that Moss Landing Units 1 & 2 would have a reasonable chance to compete in electricity markets. As PG&E's own testimony shows, PG&E's proposals, if adopted by the Commission, would effectively eliminate Moss Landing Units 1 & 2 and other generators as competitors in electricity markets.

17.2.5.2 Gas Accord VI: PG&E's Proposals

The preceding history of the two-level rate structure, its effect on competition in the electricity industry in PG&E's service area, and the mechanisms that were developed to mitigate the competitive impacts of the two-level rate structure was presented to set the stage for a discussion of PG&E's current proposal and to begin to explain why PG&E's proposals are so damaging to competition in electricity markets and ultimately to those core and noncore ratepayers that continue to bear responsibility for the costs of the local transmission system.

At the outset, it is worth noting that despite the competitive disadvantage created by the two-level EG rate structure, Units 1 & 2 have been able to compete reasonably well against Backbone-level generators for three basic reasons:

1. Gas Accord settlements spanning 2005-2014 included a bill credit for Moss Landing Units 1 & 2 that helped mitigate the effects on competition of the two-level EG rate structure.
2. The differential between Schedule G-EG rates for Backbone-level customers and All Other Customers remained relatively narrow, averaging about 7.7 cents/Dth from 2006 through 2011.[38] Starting in 2012, however, the allocation of PSEP costs to local transmission customers resulted in a widening rate differential.
3. The years since 2012 have been drought years, and the lack of hydroelectric generation meant that gas-fired units were called on more frequently to operate. The greater demand for generation resulting from the drought and the SONGS outage allowed Units 1 & 2 to continue to operate at roughly historical levels despite the higher rate differential created by the addition of the PSEP rates.

PG&E proposes to modify the two factors that are subject to the Commission's control—to eliminate the bill credit and to widen the differential between rates for Backbone-level customers and All Other Customers for service under Schedule G-EG. The result of these proposals, as PG&E's own testimony and studies show, is to ensure that Moss Landing Units 1 & 2 will make only minimal payments to PG&E under Schedule G-EG and even smaller contributions to the local transmission revenue requirement.

[38] This figure is derived from the calculations shown in Exh. Dynegy-1, p. 17, Table 3, modified by updated information provided in Exh. Calpine-6.

17.2.5.2.1 PG&E's Proposals Make it Nearly Impossible for Moss Landing Units 1 & 2 to Compete; PG&E Projects a 1% Capacity Factor for These Units

Starting in 2015, PG&E has proposed to more than **double** the rates for All Other Customers under Schedule G-EG while decreasing the Backbone-level rate by 23%. The 102% increase for the All Other Customers rate of Schedule G-EG is rate shock by any definition. The Commission has often limited rate increases to 10% or less and at the most extreme has indicated that a 20% increase "does not represent a reasonable balancing of our ratemaking goals."[39] In this proceeding, PG&E proposes an increase in the All Other Customers rate that is ***five times more*** than the level of increase the Commission determined was not a reasonable balancing of ratemaking goals.

PG&E also proposes to increase the rate differential between Backbone-level and All Other Customers rates to 88 cents/Dth in 2015, far more than the 33.4 cent/Dth differential in effect on January 1, 2014 (which includes the PSEP increase)[40] and about ***four times more*** than the 20.2 cent/Dth differential agreed to for 2011 in Gas Accord V.[41] The resulting rate differential, if adopted by the Commission, would make it nearly impossible for Moss Landing Units 1 & 2 to compete against those generators who can take advantage of the Backbone-level rate, as shown by PG&E's own analysis and testimony.

One of the most striking pieces of testimony in this proceeding grew out of PG&E's effort to rebut Dynegy's testimony on the single EG rate option.[42] In an attempt to show the effect of the single EG rate proposal on electricity markets, PG&E's witness Curtis Hatton reported on the results of an analysis using PLEXOS, a sophisticated production

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[39] D.90-12-066, 38 CPUC2d 432, 444, 1990 Cal. PUC LEXIS 1285, *32.
[40] Exh. PG&E-2, p. 17-11, Table 17-5.
[41] D.11-04-031, Appendix A (Gas Accord V Settlement), Appendix B, Table B-1. The differential is based on class-average illustrative rates for 2011.
[42] Exh. PG&E-43.

simulation model. The testimony summarized a PLEXOS analysis that compared the capacity factors of eight generation units, four connected to the backbone and four connected to the local transmission system, under the single EG rate and under PG&E's proposed EG rates and rate structure. As might be expected, the analysis showed that the capacity factors of four large backbone-level combined cycle units decreased with the single EG rate, when the advantage provided by the Backbone-level rate was removed.[43] What was more striking were the results for generators under PG&E's proposed rate increase, which dramatically illustrated the competitive effects of the two-level EG rate combined with the large rate differentials PG&E proposes.

For Moss Landing Units 1 & 2, the capacity factors dropped precipitously to 1%,[44] well below historical levels of operation (while Gateway and Colusa, two Backbone-level plants owned by PG&E, had significantly higher capacity factors under PG&E's proposal than under a single EG rate structure). At that level of production and at PG&E's proposed rates, Moss Landing Units 1 & 2's annual payments to PG&E would total only about $645,000,[45] and the units' contribution to the costs of the local transmission system would be only about $566,000,[46] far less than the payments and contributions the units have provided in recent years. From 2012 through 2014, for example, Dynegy paid PG&E between $10 million and $16 million annually for gas transportation for Units 1 & 2 under Schedule G-EG, and the units' contribution to the local transmission revenue requirement has ranged from $3.6 million to $7.8 million.[47] PG&E's proposed rates and rate structure for EG customers, if adopted by the Commission,

[43] Exh. PG&E-43, p. 17B-6, Table 17B-1.
[44] Exh. PG&E-43, p. 17B-6, Table 17B-1.
[45] (8760 hour per year X 1% capacity factor = 87.6 hours of operation) X 1,020 MW capacity X 7.200 heat rate X PG&E's proposed rate for All Other Customers of $1.003/Dth = $645,264.
[46] Of the proposed $1.003 rate for All Other Customers, 88 cents is the charge for local transmission service.
[47] Exh. Dynegy-1, p. 17.

would reduce the contribution to the local transmission revenue requirement from Moss Landing Units 1 & 2, one of the largest EG customers on the local transmission system, to a small fraction of its historical contributions.

A 1% capacity factor means that a machine that is capable of operating almost 7900 hours per year (at a 90% capacity factor) would actually operate less than 90 hours annually. To put this statistic in human terms, it would be as if a person who ordinarily worked 40 hours a week for 50 weeks a year were instead limited to 20 hours of work for the entire year.

The eventual effect of PG&E's rate proposals will be to drive existing electric generators served by the local transmission system out of business and to guarantee that new gas-fired plants will be located near the backbone system. More immediately, if EG customers served by the local transmission system are required to pay 88 cents/Dth more than EG customers connected to the backbone system, as PG&E proposes, backbone-level units will be dispatched more often than comparable (or even more efficient) units on the local transmission system. But under PG&E's proposals, Backbone-level customers make **no** contribution to the costs of the local transmission system.[48] As a result, the combination of the two-level rate structure and PG&E's proposed increases for local transmission EG customers creates a loss of the revenues needed to meet the costs of the local transmission system in two respects: first, when the local transmission generators cannot compete in electricity markets and are not dispatched, requiring no gas transportation services and producing no contribution toward the local transmission revenue requirement, and second, when Backbone-level EG customers are dispatched instead of local generation units (because of their 88-cent/Dth rate advantage) and although they require gas transportation service, they make no contribution toward the costs of the local transmission system.

[48] Exh. PG&E-2, p. 17AtchA-4, Table 17-D.

The loss of revenues to cover the costs of the local transmission system has become more acute as more generation is produced from EG customers served by the backbone system. In 2000, for example, only about 2.5% of PG&E's total load and 0% of the EG units formerly owned by PG&E were receiving backbone-level service,[49] and all EG customers contributed to the cost of the local transmission system. With the bifurcation of the EG customer class and the associated incentive for EG customers to connect to the backbone, a much larger percentage of electric generation originates with generators who pay the Backbone-level rate and make no contribution to the costs of the local transmission system. In 2013, for example, throughput for Backbone-level EG customers was 133,020 MDth, exceeding the 112,738 MDth consumed by EG customers connected at the local transmission level.[50]

The loss of EG customers' contributions to the local transmission system, however, means that other customers will be forced to make up the shortfall. Under PG&E's post-test year allocation proposal, any shortfall in recovery of the authorized local transmission revenue requirement (such as would happen if local transmission-level EG customers operated at a 1% capacity factor) will be allocated to all remaining noncore customers.[51] As the rates for noncore customers on the local transmission system increase even more, more noncore customers will migrate to a different location or go out of business, and the loss of their contributions to the local transmission revenue requirement will exacerbate the rate escalation even further.

The challenge confronting the Commission in this proceeding is to find a way to retain the contribution to the local transmission revenue requirement of EG customers served by the local transmission system. The rates and rate structure proposed by PG&E mechanically

[49] Exh. Calpine-1, p. 8.
[50] Exh. PG&E 15, pp. WP14-53 and WP14-54.
[51] RT 4069-4071 (Hoglund/PG&E).

apply certain principles of rate setting (while ignoring many others) in a way that is guaranteed to reduce the significant contribution EG customers now make toward the costs of the local transmission system. Moss Landing Units 1 & 2 are a prime example: Rather than contributing $4 million to $7 million toward the local transmission revenue requirement, as Moss Landing has in recent years, under PG&E's proposed rates and rate structure the contribution of Units 1 and 2 would be reduced to about $566,000.

Thus, this proceeding presents the Commission with a stark choice:

- If the Commission provides Moss Landing Units 1 & 2 with a reasonable opportunity to compete in electricity markets, Dynegy can continue to pay PG&E $10 million to $16 million in gas transmission rates and to contribute $3.6 million to $7.8 million toward the local transmission revenue requirement each year.
- On the other hand, if the Commission approves PG&E's proposals without any recognition of Unit 1 & 2's unique circumstances or any accommodation of the competitive impacts of PG&E's proposal, then ***according to PG&E's own analysis and testimony,*** Dynegy will pay only $645,000 in gas transportation rates and contribute only $566,000 toward the local transmission revenue requirement, at best, on the tenuous assumption that Units 1 & 2 can remain economically viable at a 1% capacity factor.

The choice between these alternatives seems clear, and the primary issue the Commission needs to resolve is the form that an accommodation to Moss Landing Units 1 & 2 should take.

17.2.5.2.2 Arguments in Favor of PG&E's Proposed Rate Structure Ignore the Real-World Effects of the Proposal

Despite the clear anticompetitive effects of PG&E's proposed rates and rate structure for transportation services provided under Schedule G-EG, some parties have advanced arguments supporting PG&E's proposals. These arguments, however, do not directly confront the effects of PG&E's proposals on competition in electricity markets.

17.2.5.2.2.1 SMUD Treats "Cost Causation" as Dogma Without Giving Consideration to How the Principle Is Applied in Practice

SMUD supports PG&E's two-level rate structure for Schedule G-EG because "it upholds cost causation principles for the EG-BB customer class that have been a cornerstone of Commission rate-making,"[52] an approach that SMUD characterizes the Commission's "longstanding principle."[53] SMUD also opposes any proposals that would "cause SMUD to pay for PG&E local gas transmission service it does not use" and asserts that such proposals require SMUD and other Backbone-level EG customers to "subsidize" customers served by the local transmission system.[54] These assertions misstate the Commission's policies and practices and miss the mark in several respects.

First, Dynegy does not agree with SMUD's claim that Dynegy is seeking or expecting a subsidy. In fact, Alan Isemonger, Dynegy's witness, expressed concerns that the current rate structure violated cost-causation principles and required Moss Landing Units 1 & 2 to pay far more than their fair share of PG&E's costs of providing service.[55] The evidence in this proceeding is that Moss Landing Units1 & 2 pay far more than PG&E's cost of providing gas transportation service to them. From 2012 through 2014, for example, Moss Landing Units 1

[52] Exh. SMUD-1, p. 4.
[53] Exh. SMUD-1, pp. 4, 15.
[54] Exh. SMUD-1, p. 7.
[55] Exh. Dynegy-1, p. 30.

& 2 paid nearly $33 million for gas transportation under Schedule G-EG, including a contribution of over $18 million toward the local transmission revenue requirement, and under PG&E's proposed rates *if* there were typical gas usage, Moss Landing 1 & 2 would pay nearly $23 million in 2015 toward the local transmission revenue requirement.[56] PG&E's actual cost of serving Units 1 & 2 over a fully depreciated pipeline is certainly far less than Unit 1 & 2's contribution.

While cost-causation is an important consideration in rate setting, even SMUD's witness acknowledged that the Commission considers "level of service and reliability and a whole host of other factors" when it sets rates.[57] Moreover, there are abundant illustrations of Commission-authorized rates that require customers to pay for services they do not receive and, in SMUD's view, to "subsidize" other customers. Low-income programs, energy efficiency programs, and economic development programs are all targeted to a narrow class of ratepayers, but are nevertheless supported by the general body of all ratepayers to promote the greater public good. More generally, customers in one portion of PG&E's gas transportation system do not make use of other, distant portions of the system. For example, Moss Landing Units 1 & 2 do not make use of the hydraulically separate local transmission system that serves PG&E's Humboldt generating plant,[58] but Dynegy is nevertheless required to pay for the costs of that distant system, due to the Commission's policy of maintaining uniform, geographically averaged rates for the same customer class and schedule throughout PG&E's system. Because of this basic policy, many (if not most) customers pay for parts of the PG&E gas transportation system they do not actually use.

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[56] Exh. Dynegy-1, p. 21. PG&E's own PLEXOS analysis, however, shows that Units 1 & 2 will not be able to achieve anything close to "typical gas usage," and the units' contribution toward the local transmission revenue requirement will be only about $566,000.
[57] RT 4377 (Ingwers/SMUD).
[58] RT 2797-2798 (Christopher/PG&E); Exh. PG&E-2, pp. 10-13.

SMUD's assertion that the Commission's "cornerstone principle" is cost-causation oversimplifies the Commission's actual practice. While cost of service is one of the factors the Commission typically considers when its sets rates, the Commission's essential function in setting rates is to ensure that rates are "just and reasonable"[59] and nondiscriminatory.[60] Beyond these essential functions, however, when setting rates the Commission also responds to legislative directives and policy determinations and furthers the actions and policies that the Commission determines are in the public interest.

In addition, the Commission has recognized that the pursuit of rates based on cost of service has to be moderated by other concerns. For one thing, pursuit of cost-based rates, if taken to an extreme, would require individualized rates for each customer, a practical impossibility. Additionally, pursuit of extreme cost-based rates would conflict with the broader and more important goal of pursuing the public interest, as determined by the Commission and the Legislature. At times the Legislature determines that certain customers should receive rate benefits and directs the Commission to act accordingly, and at times the Commission makes similar determinations on its own. For example, the Legislature has created special rate treatments for frozen food processors,[61] steel producers,[62] and cogenerators.[63] The Commission likewise exercises its discretion to depart from a strict cost-causation approach when it deems that such an action is in the public interest, for example, by setting rate caps when large rate increases would create a hardship for customers.

In actuality, the Commission neither religiously adheres to nor totally rejects the pursuit of cost-based rates. The first approach, as discussed above, leads to a separate tariff

[59] Pub. Util. Code § 451.
[60] Pub. Util. Code § 453.
[61] Pub. Util. Code § 743(b).
[62] Pub. Util. Code § 743(a).
[63] Pub. Util. Code § 454.4.

schedule for each customer, based on the specific costs of serving it, and the second approach leads to a single tariff schedule for all customers served by PG&E. The Commission operates somewhere in the middle of these two poles, grouping similarly situated customers into customer classes and then developing a handful of tariff schedules to fit the circumstances of the customers within a class. Rates are generally set to correspond to the overall costs of serving customers falling within a particular schedule, but the Commission is neither a slave to cost-based rates nor particularly troubled when some customers are required to pay for services that, strictly speaking, they do not use.

This principle is commonly encountered in other contexts. Some of the money we may pay in gasoline taxes, for example, is used to construct and maintain highways that we may never drive on, because the state Legislature and the U.S. Congress have determined that the public interest is served by having a statewide and nationwide integrated network of highways.

In the real world, then, what some parties characterize as "subsidies" are inherent in the Commission's ratemaking policies: urban customers "subsidize" higher-cost rural customers, long-time customers "subsidize" new arrivals, customers served by fully depreciated facilities (like Most Landing Units 1 & 2) "subsidize" those served by newly constructed facilities. As the Commission noted in D.04-05-061, even Calpine acknowledged that "'as a matter of social policy, the Commission may choose to provide subsidies to one class of customers at the expense of others …' and that it is 'difficult to eliminate all subsidies from rates, and that rate averaging is, to some extent, necessary.'"[64] The Commission has determined that cost sharing of this sort is in the public interest and has set rates accordingly.

One pertinent example of this approach was the Commission's treatment of the rates for PG&E's Expansion Project, which significantly increased PG&E's transmission

[64] D.04-05-061, p. 22.

capacity from Malin to Kern River Station. For the Expansion Project, the Commission adopted a postage-stamp rate, *i.e.,* a single rate for all shipments using the Expansion, regardless of delivery point.[65] The Commission's rate setting was criticized and challenged as creating a subsidy "by northern California shippers whose gas does not traverse the length of the Expansion."[66] In other words, those shippers who used only a portion of the Expansion complained that they were forced by the single rate to pay for "services that they do not receive"; they did not use the Expansion beyond their specific delivery point and objected to having to pay a rate that included the costs of other portions of the system.

The Commission rejected those arguments, based on public policy considerations. The Commission affirmed the postage stamp rate for the Expansion Project because the rate would encourage efficiencies of scope and scale and promote the economic development of the state as a whole, not just of certain segments.[67] Moreover, the Commission noted that the Expansion would not have been built if it had served only northern California shippers.

The arguments presented in this proceeding are strikingly parallel to the arguments the northern California shippers made and the Commission rejected in the Expansion case. Like SMUD, the shippers argued that they should not be charged as much as other customers because they used only a portion of the system. In the Expansion case, the Commission rejected those arguments because it concluded that (1) the broader public interest was served by the efficiencies inherent in a larger system, and (2) the Expansion would not have been built without the broad participation of all customers.

As in the Expansion case, in this case SMUD and others seek to benefit from a portion of the system—the backbone system—that would not have been built in anything like its

[65] D.90-12-119, 39 CPUC2d 69, 163 (Conclusion of Law No. 17).
[66] D.91-06-017, 40 CPUC2d 497, 504.
[67] D.91-06-017, 40 CPUC2d 497, 504.

current dimensions without the support of all customers. Some of these parties seem perfectly willing to let other customers shoulder the burden for construction of the backbone system, only to come in later and ask for special rate breaks because they are in a position to connect directly to this portion of the system and bypass the remainder of the system. As in the Expansion case, the Commission should reject these short-sighted arguments in favor of a solution that serves the larger public interest.

17.2.5.2.2.2 The Change in Rate Structure Could Not Have Been Anticipated

Calpine also supports PG&E's proposed rate structure and focuses in particular on the view that the adoption of the two-level rate in Gas Accord III was especially disadvantageous for Moss Landing Units 1 & 2.

Calpine's witness Beach seems to argue that the developers of Moss Landing Units 1 & 2 should have anticipated the change in transportation rate structure for EG customers and built a lateral to the backbone when the new units were constructed. Mr. Beach went through a lengthy summary of the history of gas rates in an attempt to support his view that "it is disingenuous to suggest that . . . the adoption of backbone-level rates in 2003 represented an unexpected or unprecedented policy change on the PG&E system."[68] The witness was selective in his historical review, however, and a more complete look at the Commission's actions leads to the opposite conclusion, that PG&E's rate structure shifted dramatically 30 months after Units 1 & 2 started operating in July 2002,[69] precisely the conclusion that Mr. Beach was trying to rebut. The Commission's decisions over the period covered in Mr. Beach's historical review, including some of the decisions he cited, paint a different picture from the one presented in his testimony:

[68] Exh. Calpine-1, p. 11.
[69] Exh. Calpine-1, p. 3, quoting Exh. Dynegy-1, pp. 6-7.

- In D.95-12-053, the decision in PG&E's 1994 Biennial Cost Allocation Proceeding, SMUD urged the Commission to adopt a backbone-level rate, as Mr. Beach noted.[70] The Commission, however, rejected SMUD's recommendation and did not adopt a backbone-level rate.[71]
- Although the Commission had urged the parties to the Gas Accord I settlement negotiations to resolve the backbone-level rate issue,[72] the settlement approved by the Commission did not approve backbone-level rates.[73] In fact, Gas Accord I provided, "All on-system transmission-level end-users must pay local transmission charges"[74] and "The local transmission charge collects local transmission costs and is applicable to all on-system end-users."[75]
- When CPN Pipeline in September 2000 asked the Commission to compel PG&E to interconnect PG&E's backbone system to CPN's proprietary gas pipeline so that it could provide service to three new power plants, the Commission vehemently rejected the request, saying:

  > PG&E argues, and we agree, that this Commission has repeatedly been asked to approve a backbone-only gas transportation rate, and that we have consistently declined. [76]

  The Commission went on to state unambiguously that:

  > The relief requested in this application, for the Calpine merchant power plants to be exempt from

[70] Exh. Calpine-1. p. 6.
[71] D.95-12-053, 63 CPUC2d 414, 450-451; RT 3652 (Beach/Calpine).
[72] D.95-12-053, 63 CPUC2d 414, 451.
[73] RT 3653 (Beach/Calpine).
[74] Gas Accord I, Appendix B to D.97-08-055, § II.E.14.b.
[75] Gas Accord I, Appendix B to D.97-08-055, § II.H.1.e.
[76] D.01-05-086, Exh. Dynegy-3, p. 15.

paying the local transmission charge, does not comport with Commission decisions and policies.[77]

Thus, in May 2001, about a year before Moss Landing Units 1 & 2 began operation, the Commission's explicit view of its decisions and policies was that **all** EG customers should pay local transmission charges. It was hardly disingenuous, as Mr. Beach charged, for the developers of Moss Landing Units 1 & 2, when making a half-billion dollar investment, to rely on the Commission's own words and decisions, rather than a patchwork of historical scraps pieced together a decade later.

Even when the Commission endorsed the changed gas transportation rate structure in D.03-12-061, the path to that determination was far from smooth. In his proposed decision, Administrative Law Judge (ALJ) John Wong, the ALJ who presided over the proceeding and heard all the evidence, concluded that "the backbone-level rate structure proposal is not adopted."[78] ALJ Wong cited two primary reasons for rejecting this proposal. First was the concern that "customers who are not in a position to directly connect to the backbone will be harmed the most," while "those able to connect to the backbone, benefit."[79] "The resulting cost shift is not equitable," ALJ Wong concluded.[80] The second reason was that "there are complex policy issues that must be considered," including consideration of the interests of "3.8 million core and noncore customers."[81] The backbone-level rate proposal required "careful thought" about "who will end up paying for the cost of local transmission." On balance, ALJ Wong

[77] D.01-05-086, Exh. Dynegy-3, p. 19.
[78] Exh. Dynegy-4, Proposed Decision of ALJ Wong, November 18, 2003, p. 371.
[79] Exh. Dynegy-4, Proposed Decision of ALJ Wong, November 18, 2003, pp. 368-369.
[80] Exh. Dynegy-4, Proposed Decision of ALJ Wong, November 18, 2003, p. 369.
[81] Exh. Dynegy-4, Proposed Decision of ALJ Wong, November 18, 2003, p. 370.

concluded that "we are not prepared today to decide whether those customers who connect directly to the backbone should be able to avoid local transmission charges."[82]

Ultimately, the Commission did not adopt ALJ Wong's recommendations. Then-President Peevey sponsored an alternate proposed decision that adopted the two-level EG rate structure that included a Backbone-level rate that excused those customers from making any contribution to the costs of the local transmission system. After barring reply comments on the alternate,[83] the Commission, rather than follow the ALJ's recommendation, instead approved the alternate sponsored by President Peevey on a 3-2 vote. The alternate was put together so hastily that the Decision's summary of issues and their resolution, carried over without modification from the ALJ's Proposed Decision, still indicated that the Decision had rejected the backbone-level rate.[84]

Thus, a more complete review of the history of the backbone-level rate before the Commission confirms the accuracy of Mr. Isemonger's statement that "30 months after Units 1 & 2 went into service the rate structure started shifting dramatically"[85] and that the change in the structure of gas transportation rates that the Commission adopted in December 2004 came with little warning. It is simply not accurate to suggest that any "reasonably well-informed developer" of a large gas-fired power plant in 1999-2002, when Moss Landing Units 1 & 2 were being planned, permitted, and constructed, should have anticipated that a radical change in the structure of gas transportation rates would be implemented in 2005.[86] It is significant that in May 2001, seven months after Moss Landing Units 1 & 2 were certificated by the CEC and well after the start of construction, the Commission stated that "this Commission has repeatedly been asked to

[82] Exh. Dynegy-4, Proposed Decision of ALJ Wong, November 18, 2003, p. 371.
[83] See D.04-05-061, pp. 12-13.
[84] D.03-12-061, Exh. Dynegy-5, Appendix B, p. 6; RT 3659.
[85] Exh. Dynegy-1, p. 7.
[86] Exh. Calpine-1, pp. 10-11.

approve a backbone-only gas transportation rate, and . . . we have consistently declined,"[87] and "The relief requested in this application, for the . . . merchant power plants to be exempt from paying the local transmission charge, does not comport with Commission decisions and policies."[88]

17.2.5.3 Options for Mitigating the Anticompetitive Effects of a Two-Level EG Rate Structure and Maintaining the Ability of Moss Landing Units 1 & 2 to Compete in Electricity Markets

The sheer size of PG&E's requested rate increase and the acknowledged need to improve the safety of the gas transportation system makes it unlikely that the Commission will be able to reduce the local transmission revenue requirement to a level that would allow Moss Landing Units 1 & 2 and other EG customers served by the local transmission system a reasonable chance to compete successfully in California energy markets. For that reason, Dynegy has proposed a number of options that would help counteract the anticompetitive effects of the two-level EG rate.

With some exceptions, the parties that have addressed this issue seem to acknowledge that Moss Landing Units 1 & 2 have been put at a competitive disadvantage by the switch to a two-level rate structure for Schedule G-EG, but recommendations about what to do about this problem vary widely. For its part, Dynegy has attempted to present some realistic and effective options for addressing this problem for the Commission's consideration. Other parties have also made some suggestions that are less focused on addressing the problem effectively and that raise some significant implementation concerns. In this section of the brief, Dynegy will review the advantages and disadvantages of the options that have been proposed in this proceeding.

[87] D.01-05-086, Exh. Dynegy-3, p. 15.
[88] D.01-05-086, Exh. Dynegy-3, p. 19.

17.2.5.3.1 Single EG Rate

One option for mitigating the anticompetitive effects of the two-level EG rate structure is to return EG customers to the rate structure that prevailed before the Commission's decision in Gas Accord III was implemented. Before that time, all transmission-level (including backbone-level) customers paid rates that contributed toward the costs of the local transmission system,[89] as well as the costs of the backbone transmission system. As a remedy to the anticompetitive effects of the two-level rate structure on electricity markets, a reinstituted single EG rate could apply only to customers served under Schedule G-EG and could renew the principle that all EG customers should contribute to the costs of the local transmission system.

The primary benefit of the single EG rate is that is allows for fair competition among all electric generators served by PG&E's gas transmission system.[90] As the Commission found when it adopted a single EG rate for the Sempra gas utilities, "Competition among electric generators should be based on the efficiency of generating units and the shrewdness of their owners in the gas procurement and financial markets . . . ,"[91] and not on the location of a plant in relation to a new rate structure.

The single EG rate has the significant added benefit of promoting the safety of the PG&E transmission system. In its application, PG&E identified the enormous capital investment required to ensure the safe operation of its gas transmission system. The bulk of these investments were on the pipelines and related facilities classified as the local transmission system. By applying the two-level rate structure of Schedule G-EG and a nominally cost-based approach to allocation, PG&E somewhat mechanically arrived at proposed rates that increased the All Other Customer rate in Schedule G-EG by over 100%.

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[89] Gas Accord I, Appendix B to D.97-08-055, § II.E.14.b.
[90] Exh. Dynegy-1, p. 38.
[91] D.00-04-060, slip op., p. 144 (Finding of Fact No. 33).

PG&E's proposal unduly places the burden of safe operation of the gas transmission system on EG customers served by the local transmission system. **All** customers, not just those served by the local transmission system, benefit from the safe operation of PG&E's gas transportation system, and the costs of safety should be spread more broadly. Under the Gas Accord I rate structure that prevailed until 2005, the costs of the transmission system were shared more broadly, and all transmission customers were obligated to help pay the costs of the local transmission system. The single EG rate restores this sharing among a smaller, but significant, group of transmission customers, the gas-fired electric generators that are among the largest customers of gas transportation services.

Thus, the single EG rate structure aligns with the Commission's commitment to safety by ensuring that the cost of safety does not unfairly fall on a relatively small customer group.

The single EG rate structure's simplicity and equal treatment of all EG customers are also the source of some of its criticisms. Because in its pure form it would apply to all EG customers, a single EG rate, without further modifications, would not distinguish between units, like Moss Landing Units 1 & 2, that were planned and constructed before the change in rate structures, and units that were constructed later, in full awareness of the two-level rate structure. It could also disadvantage generators that are in some ways the mirror image of Units 1 & 2– units that invested in laterals to the backbone in reliance on the two-level rate structure in effect when they were planned and constructed.

Despite these criticisms, the single EG rate is still the simplest way of assuring that gas-fired generators in PG&E's service area compete on the basis of efficiency and the business shrewdness of their owners and for sharing the costs of a safe gas transmission system.

It ensures that the largest gas transportation end-use customers (*i.e.*, the generators served under Schedule G-EG) all contribute to the greatly increased costs required to ensure the safety of the local transmission system, as they did under Gas Accord I. The huge increase in the local transmission revenue requirement is largely the result of the investments that PG&E has identified as needed for a safe gas transportation network, and **all** customers, regardless of their service level, benefit from a safe system.

17.2.5.3.2 Continuation and Modification of the Bill Credit

The bill credit was instrumental in allowing Units 1 & 2 to survive the competitive disadvantage of the two-level rate structure, as discussed above, and with modifications it could continue to be used to allow Moss Landing Units 1 & 2 a reasonable opportunity to compete in electricity markets.

The bill credits adopted as part of Gas Accords III, IV, and V were an implicit recognition of the equities of Moss Landing Units 1 & 2's situation. It just was not fair to "reward" a half-billion dollar investment in badly needed new generation capacity with a new rate structure that increased the burnertip costs of the new units in comparison with units that were bidding in direct competition with Units 1 & 2. The bill credits were a way of bringing Units 1 and 2's incremental costs down to a level where the units could at least occasionally succeed in that competition.

But a fixed annual bill credit had some unexpected attributes. In particular, when the demand for gas-fired generation was low, as it was in 2011 due to the high availability of hydroelectric generation, the fixed bill credit appeared to be large when it was allocated to the small electric production and greatly reduced throughput of Units 1 & 2 that year. In 2011, gas usage at Units 1 & 2 was less than half of the usage for more typical years, and the fixed bill credit actually gave Units 1 & 2 a rate advantage over Backbone-level customers for four months of high runoff.[92] When the differential between Backbone-level and All Other Customer rates widened when the PSEP costs were authorized for recovery in 2012,[93] the fixed structure left the bill credit ineffective at mitigating Moss Landing Units 1 & 2's competitive disadvantage, and the effective rate of gas transportation for Units 1 & 2 jumped to an average of 19.2 cents/Dth above the Backbone-level rate.[94]

A better design for a bill credit would be more closely tied to actual production and throughput. For example, a bill credit that set the customer's rate a fixed cents/Dth above the Backbone-level rate would more closely correspond with bidding behavior, provide a significant contribution to the local transmission revenue requirement, and ensure that the credit was linked to actual generation.

Historically, the effective rate paid by Units 1 & 2 through 2011, after accounting for the bill credit, was about 7.7 cents higher than the Backbone-level rate of Schedule G-EG.[95] If the Commission adopted a rate for Moss Landing Units 1 & 2 that reflected this historical relationship, then (1) Units 1 and 2 would continue to make a significant contribution to the local transmission revenue requirement; (2) Units 1 & 2 would have a reasonable opportunity to compete in California's energy markets; and (3) the "credit" would be invoked only when the CAISO actually dispatched Units 1 and 2.

The primary objections to the continuation of the bill credit for Units 1 & 2 take the form of two questions: Who will make up the "shortfall" resulting from continuation of the bill credit? and, How far above the Backbone-level rate should the Commission set the bill credit rate?

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[92] Exh. Dynegy-1, pp. 15, 17, Table 3.
[93] D.12-12-030.
[94] Exh. Dynegy-1, p. 18.
[95] This figure is derived from calculations shown in Exh. Dynegy-1, p. 17, Table 3, modified by updated information provided in Exh. Calpine-6.

The answer to the first question has already been alluded to. The correct question is not, "Who should make up the shortfall?" but rather, "What rate level will ensure that Units 1 & 2 have a reasonable opportunity to compete and to contribute to the local transmission revenue requirement?" PG&E's PLEXOS study has shown that without some rate accommodation, the rates requested by PG&E will reduce Unit 1 & 2's operation, and their contribution to the local transmission revenue requirement, to next to nothing. The "shortfall" will occur not because Units 1 & 2 have been granted a bill credit; the shortfall will occur because they are unable to make any significant contribution to the local transmission revenue requirement because the large differential between the two rate levels of Schedule G-EG leaves Units 1 & 2 unable to compete against plants that qualify for the Backbone-level rate. The key to retaining the contribution of Moss Landing Units 1 & 2 to the local transmission revenue requirement is ensuring that the gas transportation rate they pay allows them a reasonable opportunity to compete in electricity markets.

The answer to the second question is provided by history. Over the last few years, history shows that Moss Landing Units 1 & 2 have been able to compete with some success under a variety of market conditions when the effective gas transportation rate they pay is about 7.7 cents/Dth above the Backbone-level rate. Whether Units 1 & 2 can compete as effectively at a higher premium to the Backbone-level rate is speculative, and picking a premium that is too high runs the risk that the units' total cost of gas crosses some unseen economic threshold that results in bids that are not competitive and consequently in no dispatch (and no contribution to revenue requirements).

On balance, Dynegy recommends that the Commission should order a continuation of the bill credit, and that the bill credit should take the form of a premium above the authorized Backbone-level rate. Based on the recent history of Moss Landing Units 1 & 2's production, Units 1 & 2 should be able to compete in electricity markets and to continue to make a significant contribution to the local transmission revenue requirement at a premium of about 7.7 cents/Dth above the Backbone-level rate.[96] The bill credit could also include a guaranteed minimum contribution to ensure some contribution when gas transmission throughput is low.[97]

17.2.5.3.3 A New Rate Class

Another option for addressing the competitive implications of the two-level rate structure is to continue the unbundling that some saw as an evolution.[98] If the Commission was as concerned about unbundling and cost causation as some have claimed, then there was no particular reason to halt the "evolution" of the unbundling of the gas transmission system after the separation of the backbone and local transmission segments. PG&E has twelve "hydraulically independent" local transmission systems,[99] yet the costs of these independent systems are lumped together to form the local transmission revenue requirement, recovered through a uniform rate, even though most customers will make use of only a single local transmission system. The "evolution" of unbundling could develop separate rates for each of these local transmission systems based on the costs of each system. In that fashion, for example, Moss Landing Units 1 & 2 would no longer be responsible for the costs of operating and maintaining the lengthy local transmission system that connects PG&E's Humboldt Power Plant to the backbone. This result would be consistent with the view that a customer's transportation

[96] See Exh. Dynegy-1, p. 40.
[97] See Exh. Dynegy-1, p. 40.
[98] *E.g.*, Exh. Calpine-1, p. 10.
[99] RT 2797-2798 (Christopher/PG&E); Exh. PG&E-2, pp. 10-13.

rate should "not include the costs of the local transmission which they do not use, and have never used."[100]

Short of an unbundling of the local transmission system, a new rate class could be created for EG customers on the local transmission system. In its narrowest form, this class would consist of the power plants that have received a bill credit in recent Gas Accords, and the rate for this class would be based on the historical effective rate these customer have paid after accounting for the bill credits.[101] Other EG customers on the local transmission system might also qualify for this rate class, depending on the eligibility criteria the Commission adopts for this class.

17.2.5.3.4 Purchase or Virtual Purchase of Capacity on the Existing Pipeline

The competitive effects of the two-level EG rate could be mitigated for Moss Landing Units 1 & 2 if Dynegy purchased an interest in Line 301-G, the pipeline that serves Units 1 & 2. A variation of this idea would be virtual purchase, under which Dynegy would not actually acquire title to a portion of Line 301-G's capacity, but would make payments similar to those that would be required for an actual purchase. In each case, the acquired capacity of Line 301-G would function as a lateral connecting Moss Landing Units 1 & 2 to the backbone, and Units 1 & 2 would be eligible for the Backbone-level rate.[102] The model for this type of arrangement is SMUD's purchase of an equity interest in Lines 401 and 300 in 1996.[103]

The discussion of this option seemed to founder on the estimates of the cost of constructing a new pipeline. Estimates varied from $1 million to $6 million per mile, a range that obviously had a considerable effect on the economics of this option. While replacement cost

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[100] Exh. Calpine-1, p. 13.
[101] Exh. Dynegy-1, p. 39.
[102] Exh. Dynegy-1, pp. 40-41.
[103] See Exh. SMUD-1, p. 3.

is a useful metric, in a sense the discussion of construction costs is beside the point, because any interest Dynegy would acquire would be in a pipeline originally placed in service in 1966,[104] not in a new pipeline. Presumably, the price for an equity interest in or virtual purchase of a portion of the pipeline's capacity would reflect the age of the facility,[105] just as used cars do not command as high a price as new cars.

Further complicating the discussion of this discussion was PG&E's witness's determination to view this proposal as an actual, rather than virtual, purchase of the entirety, rather than just a portion, of Line-301-G.[106] Rather than exploring what could be an innovative way to address Moss Landing Units 1 & 2's competitive concerns, the witness reacted to a proposal that hadn't been made and inferred conditions that no one had proposed.[107]

Based on the testimony of PG&E's witness, it appears that PG&E is unwilling to give this option any further consideration. It would be difficult for Dynegy to negotiate a purchase or virtual purchase of a portion of Line 301-G without a willing counterparty.

17.2.5.3.5 Long-Term Contract

Another way to address the two-level EG rate's anticompetitive effect on Moss Landing 1 & 2 is a long-term contract that would provide transmission service to Units 1 and 2 at a specified rate. PG&E has at times entered into this sort of long-term contract with other customers, so there is precedent for this sort of agreement.

This approach resembles the anti-bypass contracts the Commission authorized under the Expedited Application Docket (EAD) when the extension of interstate pipelines into California threatened the viability of the regulated gas utilities. A long-term contract does not

[104] Exh. Dynegy-6, PG&E's Answer to Question 3.
[105] Exh. Dynegy-1, p. 41.
[106] See Exh. PG&E-40, p. 10-22 ("PG&E's local transmission lines are not for sale or lease.").
[107] Exh. PG&E-41, pp. 10-22 to 10-23; RT pp. 3128-3130 (Christopher/PG&E).

stir up any issues about ownership of the pipeline,[108] and the commitment for both parties to the contract can be for less than the life of the pipeline. A negotiated price could meet the needs of both the buyer and seller, at least in theory.

However, the long-term contract approach also carries some of the disadvantages of other approaches. The price needs to be low enough to provide Units 1 & 2 with a reasonable opportunity to compete, which may be difficult to achieve if the EAD model is followed closely. Although Dynegy could make a contribution to PG&E's margin even at a relatively low price (because Line 301-G is largely depreciated),[109] some parties think the price should be based on estimates of the cost of new construction, which vary widely.

17.2.5.3.6 Build a Third Pipeline

Another more physical approach to resolving competitive issues for Units 1 & 2 is for Dynegy to build a third pipeline to serve the Moss Landing plant. This is the preferred option of Calpine, SMUD, and PG&E, three parties who also own gas-fired power plants that compete with Moss Landing Units 1 & 2 in electricity markets. Different parties offer different rationale for this conclusion, variously arguing in favor of a third pipeline because (1) Duke Energy should have foreseen the change in rate structure and constructed a lateral when it constructed Units 1 & 2; (2) principles of cost causation require Dynegy to build a pipeline before it can avoid responsibility for the costs of the local transmission system; and (3) all other G-EG customers have built a lateral to qualify for Backbone-level service.

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[108] PG&E's witness seemed to have the same objections to a purchase of an equity interest in the pipeline, a virtual purchase, a lease, or a long-term contract. RT 3128-3130 (Christopher/PG&E).

[109] Exh. Dynegy-1, p. 41. Line 301-G was placed in service in 1966 at an initial capital cost of $4.1 million. Capital additions made since 1966 total about $1.95 million. Exh. Dynegy-6, PG&E's Answers to Questions 1, 3, and 5.

The evidence shows that building a lateral from Moss Landing to the backbone made no sense when Units 1 & 2 were planned and constructed, and it continues to make no sense today.

Mr. Beach's conclusions about what a "reasonably well-informed developer of owner of EG facilities in northern California in the late 1990s and early 2000s would have or should have known" implies that the developer of Moss Landing Units 1 & 2 should have foreseen the Commission's adoption of the two-level EG rate structure and accordingly constructed a lateral to the backbone at the same time that Units 1 & 2 were being planned and constructed.[110] That is still one of Calpine's and SMUD's recommendations for Dynegy in 2015.[111]

Whatever surface appeal this proposal might have quickly evaporates under scrutiny. Mr. Beach gave two reasons electric generators in the early 2000s might decide to build a lateral to the backbone system:

> Electric generators built laterals directly to PG&E's backbone system in order to avoid constraints on PG&E's local transmission system and to avoid the cost of the significant upgrades to PG&E's local transmission system that would have been needed to resolve these bottlenecks.[112]

(Note that Mr. Beach does not cite a desire to qualify for backbone-level rates as a reason for generators of this era to build laterals.)

The reasons Mr. Beach cited for constructing a lateral did not apply to Moss Landing Units 1 & 2. The Moss Landing site was already adequately served by two large PG&E pipelines with considerable unused capacity, made available by the retirement of five PG&E

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[110] Exh. Calpine-1, p. 10.
[111] Exh. Calpine-1, Executive Summary, p. 25; Exh. SMUD-1, p. 8.
[112] Exh. Calpine-1, p. 10.

units on the site in 1995.[113] There were no constraints on PG&E's local transmission system to avoid, and no costs of significant upgrades (and no significant upgrades) to avoid. Unlike the situation SMUD confronted when it decided to pursue its lateral in 1996,[114] Moss Landing Units 1 & 2 could be served from PG&E's existing transmission system with no significant costs or disruption. In short, there was no *physical* reason to build a lateral (because there was adequate capacity on the existing transmission system) and no *economic* reason to build a lateral (because until 2005 all transmission customers contributed to the cost of the local transmission system).

The implementation of two-level EG rate structure in 2005 created an economic reason to build a lateral (which was addressed through the bill credit in successive Gas Accords), but there still is no physical reason for Dynegy to build a lateral connecting Moss Landing to the backbone system.

Because two existing pipelines can adequately serve Moss Landing Units 1 & 2, constructing a third pipeline is senseless for several reasons:

- **Excess Capacity.** Constructing a third pipeline to serve Moss Landing would result in excess capacity. Units 1 & 2 typically use about 64% of the capacity of Line 301-G,[115] and Line 301-A currently serves Units 6 & 7 at the Moss Landing facility. If a third privately owned pipeline is built to the Moss Landing Power Plant, much of the capacity of the existing pipelines would become idle, and would not produce revenues needed to

[113] Exh. Dynegy-2, p. 14.
[114] RT 4372-4373 (Ingwers/SMUD); Exh. Calpine-1, p. 6 ("To serve these significant new gas loads, PG&E would have had to spend millions of dollars upgrading its local transmission system in the Sacramento area.").
[115] Exh. Dynegy-1, p. 41. From 2005 through 2009, Unit 1 & 2's highest use was 70% of the capacity of Line 301-G.

cover the costs of the local transmission system. Unused excess pipeline capacity results in unnecessary excess costs for ratepayers.

- **Environmental impacts.** Constructing a third pipeline to Moss Landing would result in unnecessary environmental impacts from, at a minimum, the trenching required for a 24-mile pipeline.
- **Wasted capital.** From a societal perspective, the capital required for an investment in a third pipeline paralleling two existing pipelines with adequate capacity would be wasted, and the capital required to construct the pipeline would be better invested elsewhere.

17.2.5.3.7 Conclusion on Means to Mitigate the Anticompetitive Effects of the Two-Level Rate Structure

After weighing the history of the bifurcated EG rate structure, the effects of the two-level structure on competition in electricity markets and the recovery of the costs of the local transmission system, the need to invest in pipeline safety improvement projects for the local transmission system, and other considerations mentioned in this brief, Dynegy concludes that the best and most effective way to mitigate the anticompetitive effects of the two-level rate structure while simultaneously providing for an equitable sharing of the costs of a safe gas transportation system is the single EG rate.

The single EG rate ensures the competition in electricity markets is based on efficiency and the business shrewdness of a plant's owners and allows EG customers connected to the local transmission level a fair opportunity to compete in electric markets. The single EG rate reverses the anticompetitive element of the two-level rate structure, which became increasingly apparent as the two rates diverged. In light of the Commission's post-San Bruno emphasis on safety and the high costs of the projects PG&E has said are needed for safe operation of the gas transmission system, the single EG rate provides a simple and fair way to support investments in safety and to share the costs of a safe gas transmission system among all customers.

If the Commission is reluctant to adopt the single EG rate, Dynegy's second choice is a modified bill credit for Moss Landing Units 1 & 2 and perhaps other generating facilities that meet the eligibility criteria the Commission may establish. Rather than the fixed annual bill credit incorporated in recent Gas Accords, the bill credit should be structured as a premium above the Backbone-level rate. The level of this premium should be low enough to allow Units 1 & 2 a reasonable opportunity to compete in electricity markets but high enough to provide a positive contribution to the costs of the local transmission system. History may provide some guidance on the appropriate level of the premium. From 2005 through 2011, a period when Moss Landing Units 1 & 2 were able to compete in electricity markets at a reasonable level and in a variety of market conditions, the average premium, after accounting for the bill credit, was 7.7 cents/Dth.[116] From 2012 through 2014, when the PSEP charges increased the differential between the Backbone-level rate and the All Other Customer rate, the average premium was 19.2 cents/Dth.[117] The fact that the PSEP charge collection coincided with years with low levels of hydroelectric power and the retirement of SONGS complicates the evaluation of the proper level of the premium.

Forecasts of future events in general rate cases are often based on average-year assumptions, and the same principle should apply here. Unfortunately, identifying an average weather year for these purposes is challenging. The period from 2005 through 2011 included a

[116] This figure is derived from calculations shown in Exh. Dynegy-1, p. 17, Table 3, modified by updated information provided in Exh. Calpine-6.
[117] Exh. Dynegy-1, p. 17, Table 3.

record-breaking heat storm (2006) with high electric demand, offset by a year with high levels of hydroelectric power (2011). On the other hand, 2012-2014 were the first three years of the current drought, with low levels of hydroelectric power available, complicated by the outage and eventual retirement of SONGS 2 & 3.

Under these circumstances, Dynegy proposes that the premium for the bill credit should be set at 10 cents/Dth, with a guaranteed minimum contribution from Units 1 & 2 of $100,000 per month. If history is an accurate guide of the future, with a gas transmission rate equal to the Backbone-level rate plus 10 cents/Dth, Units 1 & 2 should be able to compete in the CAISO's electricity markets with at least some success. But if the rates paid under this proposal total less than $100,000 for any monthly billing cycle, Dynegy would commit to pay the shortfall required to meet the $100,000 minimum. If the CAISO requires Moss Landing Unit 1 or 2 to be available under a Capacity Procurement Mechanism (CPM), then the bill credit would not apply to the unit in question for the duration of the CPM designation.

The bill credit should be incorporated into a contract between Dynegy and PG&E and approved by the Commission, rather than being incorporated in Schedule G-EG. The effective date of the contract should be identical to the effective date of rates approved in this proceeding. If rates are made effective as of January 1, 2015, that date should likewise be the effective date of the contract.

17.2.5.4 Conclusion on Electric Generation Rate Design

The bifurcation of the EG customer class in Gas Accord III set in motion two related challenges. First, the competitive advantage of the lower Backbone-level rate has shifted the dispatch from local transmission power plants to units sited to connect with the backbone and has increased the throughput of backbone generators from near-zero in 2000 to over 133,000

MDth in 2013,[118] and now threatens the viability of the EG customers remaining on the local transmission system. Second, the post-San Bruno emphasis on safety has resulted in PG&E's proposal to invest billions of dollars to make safety improvements to the gas transmission system, largely centered on improvements to the local transmission system, at a time when the competitive distortions and a widening rate differential will greatly reduce EG customers' contributions to the local transmission revenue requirement.

These dual challenges can begin to be addressed in this proceeding with a single set of solutions. If Moss Landing Units 1 & 2 are given a reasonable opportunity to compete in the electricity markets run by the CAISO, then they will be dispatched, operate, and use gas transportation services and will make significant payments to PG&E, including substantial contributions toward the local transmission revenue requirement. PG&E's rate proposals for the All Other Customers rate of Schedule G-EG, however, will exacerbate both challenges by increasing the rate differential between the two rate levels of Schedule G-EG to a point where local transmission generators will not be able to compete in electricity markets, will not be dispatched, will not operate, and will not make significant payments to PG&E or contributions to cover the costs of the local transmission system. The lack of contribution to the local transmission revenue requirement will require either that even higher costs will be spread among fewer customers or that needed safety improvement projects will be deferred or canceled.

The Commission should initiate its response to these dual challenges in this proceeding by:

1. Adopting a single EG rate for all customers served under Schedule G-EG. The single rate will eliminate the competitive distortions of the bifurcated

[118] Exh. PG&E-15, p. WP14-54.

rate structure while providing a solid revenue base for the safety improvement projects the Commission determines are needed.

2. If the Commission is reluctant to adopt a single EG rate, direct PG&E to enter into a contract with Dynegy (and perhaps other generators that meet the Commission's eligibility requirements) under which PG&E would provide gas transportation services to Moss Landing Units 1 & 2 at a price set at 10 cents/Dth above the Backbone-level rate for the period in question. In addition, Dynegy would commit to a minimum payment of $100,000 per month for gas transmission services.

Dynegy respectfully urges the Commission to adopt these recommendations.

17.2.6 Commercial Energy's Proposal to Modify the Noncore Customer Class Definition

Dynegy has no comments on this issue at this time.

18. Core Gas Supply

Dynegy has no comments on this issue at this time.

19. Proposals for Programs Directed Toward Small and Medium Sized Businesses

Dynegy has no comments on this issue at this time.

Respectfully submitted April 29, 2015 at San Francisco, California.

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ATTACHMENT 2

BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE STATE OF CALIFORNIA

Application of Pacific Gas and Electric Company Proposing Cost of Service and Rates for Gas Transmission and Storage Services for the Period 2015-2017.	Application 13-12-012 (Filed December 19, 2013)
And Related Matter.	Investigation 14-06-016

REPLY BRIEF OF DYNEGY INC.

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Dated: May 20, 2015

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SUMMARY OF RECOMMENDATIONS

In this Reply Brief, Dynegy Inc. responds to arguments made in opposition to its recommendations on the rate structure for electric generation (EG) customers who receive gas transportation services under PG&E's Schedule G-EG. Dynegy recommends that the Commission should adopt a rate structure that provides a reasonable opportunity for EG customers served by PG&E's local transmission system to compete in California's electricity markets and to continue to provide a significant contribution to the revenue requirement for the local transmission system and to the costs of improving and maintaining the safety of PG&E's gas transportation system. In particular, Dynegy recommends, as it did in its Opening Brief:

1. The Commission should adopt a single EG rate for all customers served under Schedule G-EG. The single rate will eliminate the competitive distortions of the bifurcated rate structure of Schedule G-EG incorporated in the last three Gas Accord settlements while providing a solid revenue base for the safety improvement projects the Commission determines are needed.
2. If the Commission is reluctant to adopt a single EG rate, the Commission should direct PG&E to enter into a contract with Dynegy under which PG&E would provide gas transportation services to Moss Landing Units 1 & 2 at a price set at 10 cents/Dth above the Backbone-level rate for the period in question. In addition, Dynegy would guarantee a minimum payment of $100,000 per month for gas transmission services for Moss Landing Units 1 & 2.

BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE STATE OF CALIFORNIA

Application of Pacific Gas and Electric Company Proposing Cost of Service and Rates for Gas Transmission and Storage Services for the Period 2015-2017.	Application 13-12-012 (Filed December 19, 2013)
And Related Matter.	Investigation 14-06-016

REPLY BRIEF OF DYNEGY INC.

In its Opening Brief, Dynegy Inc. (Dynegy) outlined how the requests of Pacific Gas and Electric Company (PG&E) in this proceeding, if granted, would have effects that could interact to frustrate the Commission's efforts to ensure the safety of PG&E's gas transportation system.

- First, PG&E proposes a huge investment in projects that it concludes are necessary for the safety of the gas transportation system.
- Second, PG&E proposes a rate design for electric generation (EG) customers, some of the largest consumers of PG&E's gas transportation services, that excuses a large segment of this class from bearing its fair share of the costs of these safety investments.
- Third, PG&E proposes to allocate the costs of these investments in a way that ensures that other EG customers, including Dynegy's Moss Landing Units 1 & 2, will have little ability to compete in the electricity markets

conducted by the California Independent System Operator (CAISO) and as a result will burn very little gas and make only a fraction of the contribution they had historically made toward the revenue requirements of the local transmission system, where many of PG&E's safety investments will be located.

- Fourth, if PG&E's proposal for 100% balancing account treatment of gas transmission revenues is adopted, the revenue shortfall resulting from the greatly reduced throughput of EG customers served by the local transmission system will result in even higher rates for noncore customers in future years.

PG&E begins its Opening Brief by announcing that "this is not a 'business as usual' GT&S Rate Case"[1] because of the challenges related to improving and maintaining a safe gas transportation system. PG&E is correct on this point: It certainly is not business as usual for EG customers that are facing a *102% increase* in gas transportation rates. It is not business as usual for electric generation customers like Moss Landing Units 1 & 2 that are confronted with a dramatic reduction in capacity factors—from around 50%[2] down to 1%, according to PG&E's studies[3]—as a result of the competitive implications of PG&E's proposed rate increases. It will not be business as usual when the revenue shortfall resulting from these EG customers' inability to compete in electricity markets requires other customers to pay higher rates to make up for this shortfall and to bear a greater share of the cost of a safe gas transmission system.

In spite of PG&E's apparent recognition that unusual challenges require unusual responses, its proposed reactions to the post-San Bruno safety challenges are entirely "business

[1] PG&E's Opening Brief, p. ES-1.
[2] Exh. Dynegy-1, p. 6.
[3] Exh. PG&E-43, p. 17B-6, Table 17B-1.

as usual"; PG&E even relishes referring to its rate design for Schedule G-EG[4] as "status quo." When Dynegy and the Northern California Generation Coalition (NCGC) presented innovative alternative rate design proposals that would help avoid some of the detrimental consequences of PG&E's proposals and would provide a more stable support for PG&E's and the Commission's safety initiatives,[5] PG&E's response was to belittle, misinterpret, and resist the proposals while clinging even more firmly to the approaches that created the current set of challenges.

In this Reply Brief, Dynegy will respond to the objections and arguments that PG&E and others have raised to the constructive proposals Dynegy presented to begin to address the challenges of the Commission's renewed and emphatic commitment to safety. As PG&E observes, there has been a sea change in the gas transmission system that cannot be successfully addressed with "business as usual" solutions.

EXECUTIVE SUMMARY

Dynegy began its participation in this proceeding with a goal of ensuring that its Moss Landing Units 1 & 2 would continue to have a reasonable opportunity to compete in the CAISO's electricity markets. The ability of Moss Landing Units 1 & 2 to compete is jeopardized by the 102% rate increase PG&E proposed for these and similarly situated electric generation customers and by PG&E's proposal to continue the bifurcated rate structure incorporated in the last three Gas Accord settlements.

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[4] Schedule G-EG applies to gas transmission service for electric generation customers within PG&E's service territory. EG customers, like other noncore customers, must also arrange for transportation on PG&E's backbone pipeline system under one of several available schedules (*e.g.*, Schedule G-AFT) and for transportation on the interstate pipelines that deliver gas from gas production areas to PG&E's system.

[5] Dynegy does not purport to suggest that its participation in this proceeding was entirely for altruistic motives. Dynegy primary goal is to have a reasonable opportunity for Moss Landing Units 1 & 2 to compete in California wholesale electricity markets. Given that opportunity, Dynegy will be able to make a significant contribution to the local transmission revenue requirement, as it has in past years. Some of Dynegy's proposals, however, will also more broadly promote competition in electricity markets, which in turn will produce greater revenues that can be devoted to improving the safety of the gas transmission system.

Dynegy is still concerned about ensuring that Moss Landing Units 1 & 2 have a reasonable opportunity to compete. These units were competitively disadvantaged by an earlier change in regulatory policy, but the last three Gas Accord settlements have provided mitigation of this competitive disadvantage in the form of bill credits. However, as the record in this proceeding has developed, it became clear to Dynegy that there is a broader issue in play with widespread implications.

In particular, PG&E's own analysis concluded that at PG&E's proposed rates and rate structure, the capacity factor of Moss Landing Units 1 & 2 would decline to 1%, down significantly from the roughly 50% capacity factor they have achieved in recent years. That decline in capacity factor, however, also meant that Unit 1 & 2's use of PG&E's gas transportation service would decline proportionately, as would the revenues Units 1 & 2 would pay to PG&E for transportation services. Rather than contributing several million dollars a year toward the local transmission revenue requirement, Moss Landing Units 1 & 2 would contribute only about $645,000 at the 1% capacity factor that PG&E predicts if its proposals are approved.

But PG&E is depending on revenues from generators served by the local transmission system to meet the revenue requirement for the local transmission system, and that revenue requirement is much higher because of the extensive capital investments that PG&E says are necessary for a safe gas transmission system. The combination of PG&E's proposed rate increases and its proposed rate structure for Schedule G-EG could leave PG&E with insufficient revenues to complete projects needed for safety or could require ratepayers to pay even higher rates in future years to make up for the revenue shortfall resulting from PG&E's proposals.

In its testimony and Opening Brief, Dynegy presented several approaches that would address both the competitive distortion created by PG&E's proposals and the related potential shortfall of the revenues needed to support a safe gas transmission system.[6] Those proposals included:

- A single EG rate, under which all electric generators would pay the same gas transportation rate under Schedule G-EG. This proposal restores the EG rate structure that existed before Gas Accord III and is the simplest method for ensuring fair competition among electric generators served by PG&E.
- A modified bill credit would recognize the unique history of Moss Landing Units 1 & 2 and would guarantee a significant contribution toward the local transmission revenue requirement.
- A new rate class for electric generators served by the local transmission system and meeting certain eligibility criteria, or a further unbundling of the local transmission system.
- A purchase or virtual purchase of a portion of the capacity of Line 301-G, the pipeline that served Moss Landing 1 & 2, modeled after the purchase by the Sacramento Municipal Utility District (SMUD) of an equity interest in PG&E's Lines 300 and 401.
- A long-term contract for gas transportation service at a negotiated rate.

The arguments offered in opposition to these proposals have failed to provide any reasons that the Commission should not consider and, if appropriate, adopt one of these

[6] Dynegy's Opening Brief, pp. 37-46.

approaches. Dynegy accordingly urges the Commission to adopt one of these approaches to mitigate the competitive distortions resulting from PG&E's proposals and to ensure that all customers bear their fair share of the revenues PG&E requires to improve and maintain the safety of the gas transportation system.

1. Overview

1.1 Legal Issues

1.2 Policy Issues

In addition to the policy issues identified in Dynegy's Opening Brief, the arguments presented in the parties' opening briefs have highlighted another key policy issue: Who should pay for the cost of safety? Who benefits from a safe gas transportation system? Who causes the costs required to ensure and maintain a safe gas transportation system?

These questions are relevant because PG&E's proposal does not allocate the costs of its safety improvements equally or equitably among customers. PG&E allocates the costs of safety in the same way it would allocate the cost of a new valve—the costs are assigned to the functional area where the valve is installed. But safety is fundamentally different from a valve; it is a condition, not a piece of equipment, and its benefits are spread far more widely than the benefits of specific investments that are narrowly designed to improve the delivery of gas to customers.

The Commission's answers to these questions are fundamental to this proceeding, because PG&E justifies the bulk of its request as safety-related.

1.3 Summary of Revenue Requirement Recommendations

2. Safety and Risk Management Issues

3. Potential Shareholder Cost Responsibility Issues

4. Impact of Proposals on Customers

5. Ratemaking Issues

6. 2011-2014 Capital Expenditures

7. Transmission Pipe

8. Storage

17.2.5 ELECTRIC GENERATION RATE DESIGN

The subject of rate design for electric generators served under Schedule G-EG was addressed by Dynegy, NCGC, PG&E, Calpine Corporation (Calpine), and SMUD. Schedule G-EG is currently structured in a way that divides electric generation customers into two rate categories: those that qualify for the Backbone-level rate and All Other Customers. The Backbone-level rate does not include any contribution toward the local transmission revenue requirement; the All Other Customers rate includes a significant contribution toward the local transmission revenue requirements, 88 cents per Dth under PG&E's proposals.[7]

PG&E, Calpine, and SMUD advocated for the basic rate design that has been incorporated in the last three Gas Accord settlements (except for the bill credits). Dynegy and NCGC offered proposals that are designed to serve the dual purposes of moderating, if possible, the competitive effects of PG&E's proposed 102% rate increase for those electric generation customers that pay the All Other Customers rate under Schedule G-EG while spreading the EG customer class' allocated share of the costs of PG&E's enormous proposed investment in safety more broadly to all EG customers.

[7] Exh. PG&E-2, p. 17AtchA-4, Table 17-D; Reporter's Transcript (RT) pp. 3866-3867 (Niemi/PG&E).

The arguments that PG&E, Calpine, and SMUD offer in opposition to the proposals of Dynegy and NCGC can be condensed into four main assertions, which Dynegy will address in the following sections. After addressing these four main assertions, Dynegy will more briefly reply to these parties' other arguments against Dynegy's positions.

17.2.5.A Precedent

PG&E begins its brief by announcing that "this is not a 'business as usual' GT&S Rate Case" and calling the proceeding a "sea change" from prior cases.[8] When it comes to devising creative solutions to the challenges it faces from this sea change, however, PG&E reverts to the approaches that were designed to address the circumstances of the last century.

This hidebound way of thinking is particularly evident in PG&E's critiques of Dynegy's and NCGC's proposals for alternative rate designs for customers served under Schedule G-EG. PG&E seems to believe that if it dismisses these proposals, it can then safely ignore the underlying problems that these innovative approaches were developed to address.

After its assertions that "this is not a 'business as usual' GT&S Rate Case," PG&E accuses Dynegy and NCGC of proposing "to jettison more than ten years of history,"[9] later referring to a rate structure "that has been in place for more than nine years."[10] PG&E tries to give more weight to its characterizations by repeatedly referring to its proposal as a "*status quo* rate design."[11]

PG&E's view of this case is accurate in at least some respects. This is definitely not a "business as usual" rate case for customers like Moss Landing Units 1 & 2 that are faced

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[8] PG&E's Opening Brief, p. ES-1.
[9] PG&E's Opening Brief, p. 1-15.
[10] PG&E's Opening Brief, p. 17-15.
[11] *E.g.*, PG&E's Opening Brief, pp. 17-18, 17-19. PG&E seems to forget that it **opposed** the bifurcated rate design when it was initially proposed and urged the Commission to "adhere to its long-standing policy of non-bypassable local transmission charges for all customers." (See D.03-12-061, p. 358.)

with a 102% rate increase and the prospects of seeing their operation reduced to a 1% capacity factor. This is not a "business as usual" rate case for the customers who will be forced to make up the shortfall in revenues resulting from the declining operation of electric generators who have historically contributed tens of millions of dollars toward the local transmission revenue requirement.

What PG&E refers to as the "*status quo* rate design," of course, is a rate structure for Schedule G-EG that has been incorporated into the last three Gas Accord settlements. But under Rule 12.5 of the Commission's Rules of Practice and Procedure, the Commission's acceptance of a settlement "does not constitute approval of, or precedent regarding, any principle or issue in the proceeding or in any future proceeding." As Calpine's witness admitted, "By their express terms, no provisions in these [Gas Accord] settlements have precedential value in future cases."[12] Nothing in the last three Gas Accord settlements, which implemented a bifurcated rate structure for electric generation customers, in any way precludes Dynegy or NCGC from presenting rate design proposals that address the "sea change" PG&E refers to, *i.e.,* the post-San Bruno emphasis on safety, or prevents the Commission from adopting those proposed rate designs (or some other rate design) for the years that are the subject of PG&E's application.

Further, the current Commission is not bound by the actions of previous Commissions.[13] The emphasis on safety and the drastic rate increases PG&E proposes to provide safe gas transmission service justify a reconsideration of the rate design in this case. PG&E is right; there has been a sea change resulting from the San Bruno explosion, which created a need for a huge investment just to establish a basic confidence that the gas transportation system is safe. The bulk of PG&E's proposed investments in safety are for

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[12] Exh. Calpine-1, p. 18.

[13] D.88-12-083, 30 CPUC2d 189, 223-225; Pub. Util. Code § 1708.

facilities classified as part of the local transmission system, and PG&E's "business as usual" approach places a significant burden to fund those investments on core customers and in particular on EG customers served by the local transmission system. Now is not the time to perpetuate a rate design that intentionally results in a shift in dispatch of electric generators *away* from those whom PG&E relies on to fund a significant portion of the investment in safety and who contribute to the local transmission revenue requirement and *toward* those who, under PG&E's proposal, will not make any contribution to the costs of the numerous safety projects PG&E proposes for the local transmission system.

Instead of mechanically applying the rate design of recent settlements to vastly changed circumstances, as PG&E proposes, the Commission should consider how the costs of providing a safe gas transportation system can be equitably shared among all customers and all customer classes. Safety is an issue that transcends the usual categories of rate design: core v. noncore, backbone v. local transmission, residential v. commercial v. industrial v. electric generation. Safety concerns **all** customers, and the rate design adopted in this proceeding should fairly spread the costs of safety among **all** customers.

17.2.5.B Cost Causation

17.2.5.B.1 The Need for a Safe Gas Transmission System Is Not "Caused" by Only Some Customer Classes

PG&E, Calpine, and SMUD refer repeatedly to what they describe as the principle of cost causation, without ever saying exactly what that principle requires. The closest these parties come to offering a description refers to marginal cost pricing, where cost causation means that "the rates charged should reflect the change in the utility's costs that would actually occur if there were an increase in demand."[14]

[14] D.92-12-058, p. 17; 1992 Cal. PUC LEXIS 970, *35, quoted in Calpine's Opening Brief, pp. 42-43.

This definition exposes a fundamental misunderstanding about the nature of this rate case. The driver of this rate case is not an increase in demand, although there are some projects like the proposed Line 407 that respond to demand increases. This rate case is driven by a heightened need for safety in response to the San Bruno explosion, and the principles of marginal cost pricing and cost causation that apply when demand increases have much less relevance when increased costs are not attributable an increase in demand. The challenge the Commission faces in this proceeding is to equitably allocate responsibility for the cost of ensuring safe operation of the entire gas transportation system, and principles for allocating the costs created by increases in demand are not relevant.

Moreover, glib references to "cause causation" fail to come to terms with one of the central issues in this proceeding: Who "causes" PG&E to incur the costs of investments in safety? These parties' simplistic explanation is that the costs of safety are "caused" by the customers who happen to be in a customer class that uses the facilities that PG&E has identified as safety-related projects. Even a cursory dip beneath the surface of this explanation reveals its superficiality. The people of San Bruno did not "cause" Line 132 to explode, even though their gas supply may have passed through the line. Core customers and EG customers served by the local transmission system did not "cause" Line 132 to explode, an event that eventually led to the hundreds of millions of dollars of safety-related investment that PG&E now proposes to make. The Commission has now determined—and PG&E has acknowledged—that the San Bruno explosion was caused by decades of underinvestment in and lack of management attention to the gas transmission and distribution system. As a result, the Commission has determined that it is now incumbent on PG&E shareholders to finance over a billion dollars in safety-related improvements.[15]

But considerable additional investment—$1.42 billion in capital expenditures—is needed to "help to ensure PG&E continues to safely and reliably operate its transmission pipeline assets," according to PG&E.[16] The question then becomes, "Who should pay the costs of improving the safety of the gas transportation system?" This question is quite different from the usual issue in rate cases of who should pay for the costs of investments required to extend, maintain, or improve the delivery of natural gas. When a gas transmission line is upgraded to provide service to a new industrial customer, for example, the answer is clear that the new customer should pay for the costs of the upgrade (unless the expected revenues are high enough to justify investment by the body of ratepayers).

But the purpose of the investments proposed in this proceeding is not merely to deliver natural gas; the purpose is also to improve and maintain the *safety* of the gas transmission system. Safety is not associated with any particular group of customers. A safe gas transmission system benefits *all* customers; an unsafe system can randomly affect a particular customer in unforeseeable ways, including damage to people and property and interruptions of gas service.

The Commission's recent decisions related to the San Bruno explosion make it clear that safety is an obligation a public utility owes to all of its customers and to the public at large. As the Commission has stated, "Public utilities serving or transmitting gas bear a great responsibility to the public respecting the safety of their facilities and operating practices."[17] The Commission has also construed Public Utilities Code Section 451 to require "without

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[15] In addition to the $850 million of costs that D.15-04-024 assigned to shareholders, D.12-12-030 required shareholders to bear about $635 million of costs of the Pipeline Safety Enhancement Plan. See D.15-04-024, p. 82.
[16] Exh. PG&E-1, p. 4-2.
[17] D.15-04-023, p. 27, quoting D.61269 (1960), 58 CPUC 413, 420.

qualification . . . all public utilities to provide and maintain 'adequate, efficient, just, and reasonable' service and facilities as are necessary for the 'safety, health, comfort, and convenience' of their customers and the public."[18] The Commission's decisions also refer to "the public interest in ensuring safe and reliable natural gas service,"[19] "PG&E's "ongoing obligation to operate its transmission pipeline system in a safe manner,"[20] and the need to make "PG&E's gas transmission system as safe as possible for the public, ratepayers, utility workers, and the environment."[21] Finally, the Commission required PG&E to provide a bill credit of $400 million to all customers, because PG&E "breached the trust between a regulated utility with an exclusive franchise and its customers that PG&E would maintain and operate a safe gas transmission system."[22]

The safety of PG&E's entire gas transportation system, then, is an obligation PG&E owes to the public and to all of PG&E's customers. It makes no sense to exempt one group of customers from bearing its fair share of the costs of maintaining a safe gas transmission system on the basis of the assertion that those customers have not "caused" the need for safety.[23] All customers benefit from a safe gas transportation system, and all customers should pay their fair share of the costs of providing and maintaining the safety of the entire gas transportation system.

[18] D.15-04-023, p. 249 (Conclusion of Law No. 2). See also D.15-04-021, p. 295 (Conclusion of Law No. 9).
[19] D.15-04-024, p. 234 (Conclusion of Law No. 23).
[20] D.15-04-023, p. 251 (Conclusion of Law No. 12).
[21] D.15-04-024, p. 3.
[22] D.15-04-024, p. 4.
[23] Calpine also notes that PG&E proposes increases in rates for transportation using the backbone pipelines. (Exh. Calpine-1, pp. 26-27; Calpine's Opening Brief, p. 21.) Of course, all customers, with very limited exceptions, pay for transportation from the delivery point of the interstate pipelines using the backbone pipelines, whether directly (noncore) or indirectly (core), and all customers will share in the costs of projects proposed for the backbone pipelines.

Therefore, the contention of SMUD and Calpine that they should not bear any portion of the cost of safety-related projects PG&E is proposing for the local transmission system is fundamentally flawed. PG&E has proposed these projects not merely because they improve the delivery of natural gas to local transmission customers; instead, they are needed to ensure the safety of the gas transmission system in its entirety.

17.2.5.B.2 The Commission Has Not Pursued Cost Causation as the Primary Principle of Rate Design

The second flaw in the cost causation argument is the fact that the process of unbundling and identifying the costs of gas transportation stopped with the bifurcation of rates in Schedule G-EG between EG customers served by the backbone system and those served by the local transmission system. If unbundling and cost causation were truly the honored principles that PG&E, Calpine, and SMUD assert, the costs of the local transmission system would not be recovered, as it is today, through a uniform postage-stamp rate that disguises the cost differences between the twelve hydraulically independent local transmission systems.[24] If backbone-level EG customers are excused from paying any costs associated with the local transmission system on the grounds that they don't use that portion of PG&E's transmission system, then local transmission EG customers should likewise be excused from paying the costs associated with the eleven hydraulically independent local transmission systems that they don't use. Continuing the "logic" of this argument, distribution-level customers should be excused from paying the costs of distribution lines that they do not use, and ultimately each PG&E gas transportation customer should have an individualized rate reflecting the costs of only those facilities that the customer actually uses.

[24] Exh. PG&E-2, p. 17-6; RT 3868-3869 (Niemi/PG&E).

To put this point in stark terms, if cost causation and unbundling were the ironclad principles that PG&E, Calpine, and SMUD claim, the Commission would have followed these principles to the next level at some point in the last decade. Yet the Commission has done no such thing. PG&E, Calpine, and SMUD have yet to respond to this fundamental inconsistency in their position. The Commission's actions over the past decade illustrate that the Commission considers many factors in addition to "cost causation" when it designs and sets rates.[25]

When subjected to a bit of scrutiny, these cost causation arguments are exposed as attempts by their proponents to evade any responsibility for the costs of improving and maintaining the safety of the local transmission system. These parties have failed to justify their desire to be excused from bearing their fair share of the systemwide cost of a safe gas transmission infrastructure.

17.2.5.C Operational Issues

PG&E and Calpine also contend that the two-level EG rate of Schedule G-EG is justified by operational issues. PG&E states that the backbone system is dynamic and is actively managed by operators who route gas, control pressures and adjust line inventory. By contrast, PG&E contends that the local transmission system is passive and is generally not managed downstream of the regulators that tie it to the backbone system.[26] PG&E claims that having gas-fired generators connected directly to the backbone allows PG&E to more easily manage changes in the flow of gas.[27]

These purported benefits of backbone-level generation are more a function of imprecise language than actual operation of the system. PG&E's management of the local

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[25] Dynegy's Opening Brief, pp. 38-33.
[26] PG&E's Opening Brief, p. 17-17, citing Exh. PG&E-40, p. 10-20.
[27] PG&E's Opening Brief, p. 17-18.

transmission system is limited to maintaining the pressure at the regulator where the gas transfers from the backbone to the local transmission system.[28] Similarly, PG&E does not manage the private laterals that connect backbone-level EG customers to the backbone system beyond the regulator where the lateral connects to the backbone system.[29] Referring to backbone-level EG customers as being "on" the backbone system is just a shorthand way of referring to the fact that they connect to the backbone system through a private lateral rather than through PG&E's local transmission system. Operationally, the private lateral and the local transmission system function similarly. Neither private laterals nor the local transmission lines are actively managed by PG&E's Gas Transmission Control Center or other PG&E organization.[30] Neither private laterals nor the local transmission lines have significant line inventory.[31]

The functional equivalence of local transmission lines and private laterals is illustrated by the situation of SMUD. SMUD has a 76-mile lateral that connects SMUD's gas-fired generation plants to PG&E's backbone system.[32] PG&E does not manage SMUD's lateral, like other laterals, beyond maintaining pressure at the point where SMUD's lateral connects to the backbone.[33] PG&E does not route gas, control pressure, or adjust line inventory once the gas moves onto SMUD's lateral.[34] PG&E's management of the lateral of SMUD, a backbone-level customer, is identical to and no more "active" than PG&E's management of the "passive" local transmission system used to serve other EG customers.

PG&E raised similar operational objections to Dynegy's proposal to acquire an interest or virtual interest in Line 301-G, the local transmission pipeline that serves Moss

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[28] RT pp. 3111-3112 (Christopher/PG&E).
[29] RT pp. 3112-3114 (Christopher/PG&E).
[30] Exh. PG&E-40, p. 20; RT 3111-3113 (Christopher/PG&E).
[31] Exh. PG&E-40, p. 10-20; RT 3113-3114 (Christopher/PG&E).
[32] Exh. SMUD-1, p. 3.
[33] RT 3112-3113 (Christopher/PG&E); see Exh. SMUD-1, pp. 2-3, 5-6.
[34] RT 3111-3114 (Christopher/PG&E); see Exh. SMUD-1, pp. 2-3, 5-6.

Landing Units 1 & 2, and Dynegy's proposal to enter into a long-term contract with PG&E for transmission services. PG&E claimed that a lease or purchase of capacity of Line 301-G "would complicate the operation of that facility,"[35] even though PG&E's witness somewhat reluctantly acknowledged that SMUD's ownership of a portion of the capacity of Lines 401 and 300 has not created operational problems or compromised PG&E's ability to operate those lines.[36] Similarly, PG&E's witness objected to a possible long-term contract because of a concern about potential complications arising from presumed "certain rights" that Dynegy had not proposed.[37] The witness maintained this objection even though other long-term contracts PG&E had entered into had not created operational problems and even though he acknowledged that PG&E would not agree to a contract that complicated its ability to operate the gas transmission system.[38]

The other operational benefit PG&E claims for the two-level EG rate simply makes no sense. PG&E claims that the large swings in gas demand of backbone-level EG customers is "more readily managed if they are on the backbone."[39] Apart from the point made above that these generators are not really "on" the backbone, the delivery of natural gas from the interstate pipelines to PG&E's intrastate system and on PG&E's system from the border to the Citygate is the subject of a nomination system in which electric generators and other noncore customers have a strong financial incentive to anticipate their gas needs for the next day.[40] Notably, both backbone-level and local transmission EG customers must schedule deliveries from the interstate pipelines. The anticipated gas burn for the next day may not always be accurate, but there is no evidence that local transmission EG customers do a worse job of

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[35] Exh. PG&E-40, p. 10-22.
[36] RT p. 3132 (Christopher/PG&E).
[37] Exh. PG&E 40, p. 10-23; RT pp. 3127-3130 (Christopher/PG&E).
[38] RT p. 3131 (Christopher/PG&E).
[39] PG&E's Opening Brief, p. 17-18.
[40] See Exh. PG&E-2, pp. 10-40 to 10-41.

predicting gas deliveries than backbone-level EG customers. And the tools PG&E employs to manage the imbalance between nominations and burns are exactly the same for backbone-level and local transmission EG customers.[41]

17.2.5.D Undermined Investment

The most compelling argument parties make in favor of the two-level EG rate is that proposals like the single EG rate undermine the party's investment in the laterals that connect generating plants to the backbone pipelines. SMUD, for example, argues that the single EG rate would "severely diminish the value of SMUD's prior investments in its own local transmission system."[42]

Dynegy is sympathetic to the argument that regulatory changes should not have the effect of significantly diminishing a party's investment in infrastructure. That, of course, is exactly what happened to Moss Landing Units 1 & 2 when, 30 months after the units began commercial operation, the Commission implemented the bifurcated rate for Schedule G-EG, a regulatory change that severely diminished the value of the investment in Units 1 & 2. Moreover, a comparison of Moss Landing Units 1 & 2 with SMUD's investment in its lateral demonstrates that the effect of regulatory changes on Units 1 & 2 was even more severe than the regulatory changes that SMUD fears could affect its investment in its lateral. For example, SMUD invested about $90 million to build its lateral,[43] while the developer of Moss Landing Units 1 & 2 spent nearly half a billion dollars. SMUD has received the benefit of the bifurcated EG rate for nearly 10 years. Moss Landing Units 1 & 2 operated under a uniform gas transmission rate for only 30 months before they were put into a disadvantaged competitive position by the implementation of the two-level EG rate.

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[41] See PG&E Gas Rule 21, Schedule G-BAL.
[42] *E.g.*, SMUD's Opening Brief, p. 10.
[43] SMUD's Opening Brief, p. 8, citing Exh. SMUD-1, p. 5.

Thus, SMUD persuasively argues that it should not suffer significant harm due to changes in regulatory policy. That same principle should apply to Moss Landing Units 1 & 2. A change in regulatory policy has harmed Units 1 & 2 over the last 10 years, the period covered by the rate design incorporated into the last three Gas Accord settlements, but the harm to Units 1 & 2 would reach unprecedented and unsustainable levels with the rate increases PG&E proposes in this case. This proceeding provides the Commission with the opportunity to fashion a remedy to mitigate the harm that Moss Landing Units 1 & 2 and others will incur under PG&E's proposals. Dynegy has presented several rate design options that can mitigate that harm while allowing Moss Landing Units 1 & 2 and other EG units served by the local transmission system a reasonable opportunity to compete in electricity markets.

17.2.5.E Other Arguments

17.2.5.E.1 Gas Transportation Rate Design Is Determined by the Commission and Is an Issue in this Proceeding

Calpine urges the Commission not to attempt to reform EG rate design. Not all electric generators in California pay the full PG&E tariffed rate for gas transportation, Calpine argues, and it is impossible to "level the playing field," because a host of other cost elements affect the total cost of electric generation. These cost elements include gas and electric interconnection costs, water availability, locational marginal pricing, air pollutant emissions controls, permitting costs, and financing, among other costs.[44] Any effort to equalize these multiple cost components to "level the playing field" is a "fool's errand," according to Calpine,[45] and the Commission should therefore reject Dynegy's and NCGC's proposals for a single EG rate.

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[44] Calpine's Opening Brief, pp. 49-57.
[45] Calpine's Opening Brief, p. 50.

Calpine devotes an extensive portion of its Opening Brief to rebutting arguments that Dynegy did not make and that are irrelevant to the decisions before the Commission. First, Dynegy is not attempting to "level the playing field," as Calpine repeatedly and erroneously states. Dynegy understands that many cost elements contribute to the total cost of electric generation, and Dynegy has not suggested that the Commission should attempt to impose perfect equality of those costs among the hundreds of electric generators that compete in California's markets for electricity. Instead, Dynegy has focused on a single cost element that is relevant to this proceeding, the cost of intrastate gas transportation, that will have a significant impact on competition if the Commission adopts PG&E's proposals. It was a change in regulatory policy affecting this precise cost element that distorted competition in electricity markets and placed Moss Landing Units 1 & 2 in a competitively disadvantaged position.

Second, the other cost elements that Calpine lists as affecting the total cost of electric generation are, with the possible exception of gas interconnection costs, beyond the Commission's ability and jurisdiction to alter. It is, frankly, nonsense to suggest that Dynegy is asking the Commission to do something about the cost of financing power plants or local air pollution emission control requirements.

Dynegy is not seeking cost equality in this proceeding; it is seeking to maintain a reasonable opportunity for Moss Landing Units 1 & 2 to compete in California's electricity markets. That opportunity is severely threatened by PG&E's revenue requirement and rate design proposals for EG customers, as starkly illustrated by PG&E's conclusion that its proposals, if adopted by the Commission, would result in a 1% capacity factor for Moss Landing Units 1 & 2. Dynegy has focused on the rate design for Schedule G-EG because that is where the problem originated. The combination of the bifurcated rate design and the huge investment in safety triggered by the San Bruno explosion creates a circumstance that will *prevent* Units 1 & 2 from making anywhere close to its ordinary contribution to the revenue requirement for the local transmission system, which is where the bulk of the cost of PG&E's safety projects is allocated.

Dynegy is obviously most concerned about the effect of PG&E's proposals on Moss Landing Units 1 & 2, but the same effects will also make it significantly more difficult for other generators served by the local transmission system to compete in California's electricity markets, which could initiate a migration that would eventually result in all gas-fired generation qualifying for the Backbone-level rate of Schedule G-EG, which makes **no** contribution to the local transmission revenue requirement, which in turn will require other customers to bear an increased share of the cost of a safe gas transmission system.

The Commission does not need to "level the playing field," but it should carefully consider how a failure to address the competitive implications of PG&E's revenue and rate design proposals will affect its ability to achieve the goal of improving and maintaining a safe PG&E gas transmission system.

17.2.5.E.2 The San Bruno Explosion and the Resulting Renewed Emphasis on Safety Could Not Have Been Anticipated in 2007

Calpine contends that Dynegy's and NCGC's single EG rate proposal should be rejected because Dynegy was aware of the bifurcated rate structure when it purchased the Moss Landing facility in 2007, and Dynegy should have factored the EG rate structure into the purchase price for Moss Landing.[46] There are several flaws in Calpine's argument.

First, what Calpine refers to as the "existing" EG rate structure was the product of the Gas Accord III settlement, implemented in 2005. As Calpine acknowledged, there is a "well-

[46] Calpine's Opening Brief, pp. 45-46.

known Commission rule that settlements do not set precedent for future Commission proceedings."[47] It would have been less than rational for Dynegy in 2007 to assume, without Calpine's benefit of hindsight, that a two-year old rate structure that was implemented as part of a non-precedential settlement would remain in effect for the roughly 25-year remaining useful life of Moss Landing Units 1 & 2.

Second, in 2007 the differential between Schedule G-EG's Backbone-level rate and the All Other Customers rate was roughly 15 cents per decatherm, which the bill credit for Units 1 & 2 incorporated into Gas Accord III in effect reduced to roughly 9 cents per decatherm.[48] While Dynegy could not count on these specific figures to remain in effect beyond the term of Gas Accord III, it could reasonably have discerned an intent to mitigate the competitive effects of the bifurcated rate structure on Moss Landing Units 1 & 2, in recognition of the units' unique history and the half-billion dollar investment that was devalued by the Commission's change in regulatory policy.

Third, within the bifurcated rate structure, the important factor for purposes of competition in California's electricity markets is the magnitude of the differential between the Backbone-level rate and the All Other Customers rate, not the level of the rates. Higher rates can still allow for reasonable competition if the differential between the bifurcated rates does not become too large. Dynegy had every reason to expect that the differential would continue at a level that gave EG customers on the All Other Customers rate a shot at competing successfully against less efficient units paying the Backbone-level rate. Dynegy in 2007 had no reason to expect that a gas transmission line explosion in 2010 would in late 2013 result in a proposal that

[47] Calpine's Opening Brief, p. 46.
[48] Exh. Dynegy-1, p. 13, Figure 2. With the additional throughput information contained in Exh. Calpine-6, the value of the bill credit for Moss Landing Units 1 & 2 declines from the roughly 10 cents per Dth shown in Figure 2 of Exh. Dynegy-1 to around 4 cents per Dth.

would increase the Backbone-level to All Other Customers rate differential to *88 cents per decatherm*, nearly *six times greater* than the differential in 2007.

In short, the fact that Dynegy's foresight in 2007 was not as acute as some parties' hindsight in 2015 should not bar the Commission from considering and adopting Dynegy's rate design proposals.

17.2.5.E.3 Gas Transportation Costs Are an Important Factor Affecting Competition in Electricity Markets

Calpine asserts that the Commission can ignore Dynegy's and NCGC's single EG rate proposal because generators have the possibility to earn revenues through mechanisms other than California's electricity markets, including Reliability Must-Run (RMR) agreements, negotiated agreements, sales of ancillary services and resource adequacy capacity, and extraordinary dispatch.[49]

Calpine's argument is a non-sequitur. Even if extra-market mechanisms were as remunerative and readily available as Calpine claims (and they are not), that would not cure the competitive distortions that PG&E's revenue and rate design proposals, if approved, would create in electricity markets. Even if a tolling agreement, for example, provided adequate revenues for an individual generator to continue in operation for a few years, the problem Dynegy has identified— *i.e.,* the large differential between Schedule G-EG's Backbone-only and All Other Customers rates makes it nearly impossible for EG customers served by the local transmission system to compete effectively in California's electricity markets—would persist.

Moreover, NCGC prepared a table that concisely demonstrates that gas transportation rates, at the levels PG&E proposes, would have a significant impact on electric

[49] Calpine's Opening Brief, pp. 58-60.

generators' costs and consequently their bids in competitive markets.[50] Under PG&E's proposed rates for Schedule G-EG, the cost of gas transmission for EG customers under the All Other Customers rate will increase by between $3.50 to $5.00 per MWh, depending on the generator's heat rate, while the cost for Backbone-level customers will decrease by between 27 cents and 39 cents per MWh.

Revenues from energy markets still constitute a primary source of revenues for many generators. Exceptional dispatch is "very uncommon."[51] The energy portion of exceptional dispatch is "seldom very lucrative."[52] RMR agreements have been phased out.[53] Resource Adequacy capacity revenues are not paid to all generators, and those revenues are relatively small for generators, like Moss Landing Units 1 & 2, that are not located in a Local Reliability Area.

While it may be hypothetically possible for a generator to survive on revenues from bilateral agreement, Resource Adequacy contracts, or sales of ancillary services, California's energy markets still provide a significant source of revenues for many generators, and PG&E's proposals, if adopted by the Commission, would have a significant effect on the ability of generators served by the local transmission system to earn revenues in those markets.

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[50] Exh. NCGC-1, p. 8, reproduced in NCGC's Opening Brief, p. 31.
[51] RT p. 4319 (Isemonger/Dynegy).
[52] RT p. 4322 (Isemonger/Dynegy).
[53] RT p. 4323 (Isemonger/Dynegy).

17.2.5.E.4 The San Bruno Penalties and Refunds Will Not Solve the Underlying Problem

In opposing Dynegy's and NCGC's single EG rate proposal, Calpine charges that "Dynegy and NCGC overstate PG&E's proposed rates increases in light of Decision 15-04-024."[54] Calpine is mistaken on several counts.

First, and most obviously, D.15-04-024 had no effect on PG&E's *proposed* rate increases, which have continued without significant modification since PG&E's application was filed in December 2013. Second, Calpine's argument is entirely speculative. The Commission in D.15-04-024 made it clear that the $850 million should be used only to fund projects that were found to be reasonable in this proceeding.[55] The effect of D.15-04-024 won't be known and can't be known until (1) the Commission decides the issues that were addressed in the evidentiary hearings and in this round of briefs, and (2) the Commission decides how to allocate the $850 million among the safety-related projects found reasonable in the first step. At this point, there is no reasonable way to foresee which projects will be found reasonable or how the Commission will eventually decide to allocate the $850 million.

Third, even if the entire $850 million is applied toward safety-related projects proposed for the local transmission system, the differential between Schedule G-EG's Backbone-level and All Other Customers rates may still be too great to allow generators paying the All Other Customers rate to compete effectively in electricity markets. PG&E's revenue request in this proceeding is for more than $4 billion,[56] and its proposed capital investment in transmission

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[54] Calpine's Opening Brief, p. 72. In D.15-04-024, the Commission required PG&E's shareholders to bear $850 million of safety-related investments in the gas transmission system and ordered PG&E to refund $400 million to ratepayers.
[55] D.15-04-024, p. 93.
[56] PG&E's Opening Brief, p. 1-17.

projects in 2015 is $1.42 billion.[57] Even if the cost of capital investments in transmission is reduced by $850 million, a significant rate gap will remain if the Commission accepts PG&E's proposals. Once the $850 million is exhausted, that gap will revert back to levels comparable to those proposed for 2015.[58]

In short, a $850 million contribution to the costs of safety-related projects would certainly be welcome, but it does not solve the underlying competitive problem created by the bifurcated rate structure for Schedule G-EG and the enormous rate increases PG&E proposes.

17.2.5.E.5 Dynegy's Proposals Can Be Adopted by the Commission

PG&E asserts that the single EG rate proposal lacked sufficient analysis and did not evaluate the effect of the single rate on wholesale electric prices and electric rates.

The single EG rate, however, was the rate design that was in effect until 2005, so it obviously is capable of serving as an effective rate design. In addition, PG&E, which has far greater access to resources and information than does Dynegy, performed a PLEXOS analysis of the single rate structure and concluded that it was compatible with the operation of wholesale electricity markets.[59]

PG&E and Calpine also criticize other Dynegy proposals for not providing what these parties consider sufficient analysis. Dynegy admits that it does not have the resources or access to information that PG&E does, and it cannot always provide a detailed analysis that depends on access to information that PG&E considers confidential. On the other hand, Dynegy supported its proposals with the testimony of Alan Isemonger, an expert economist with

[57] Exh. PG&E-1, p. 4-2.
[58] PG&E's proposed capital expenditures for its transmission pipeline programs total $1.42 billion for 2015-2017. Exh. PG&E-1, p. 4-2. Even if the entire $850 million is applied to these programs, $570 million of capital expenditures would still be recovered in rates under PG&E's proposal.
[59] PG&E's Opening Brief, p. 17-20, citing Exh. PG&E-43, p. 17B-5.

extensive experience in designing, evaluating, and monitoring electric markets, including those operated by the CAISO.[60] Dynegy notes that the Commission ordered changes to the rate structure for Schedule G-EG despite the fact that the details of the proposal had to be worked out in later filings and proceedings.[61]

17.2.5.E.6 Response to Arguments Against Bill Credit

Dynegy's alternative proposal to continue the bill credit that has been in effect for the last three Gas Accords, with appropriate modifications, attracted routine opposition.

PG&E argues that it is inappropriate to pick a single element of a settlement for continuation.[62] But PG&E fails to explain why the Commission is prohibited from considering and adopting a mechanism incorporated in a settlement once the term of the settlement has passed. Just because a proposal was included in an expired settlement does not mean that the Commission can't consider it for subsequent implementation.

PG&E also claims that the bill credit mechanism would create a shortfall in the collection of rates to support the local transmission revenue requirement.[63] Dynegy's Opening Brief, however, demonstrated how PG&E's proposed rates and rate structure resulted—by PG&E's own calculation—in a 1% capacity factor and payments to PG&E of only about $645,000, far lower than the amounts Dynegy has paid in recent years when a bill credit helped mitigate the gap between Backbone-level and All Other Customers rate.[64]

PG&E is looking through the wrong end of the telescope. Rather than hypothesizing about a potential shortfall from bill credits, PG&E should realize that the results of its own study show that its proposed rates and rate design will reduce the previously substantial

[60] Exh. Dynegy-1, pp. 3-4, and Appendix.
[61] D.03-12-061, pp. 370, 485 (Ordering Paragraph 6.h).
[62] PG&E's Opening Brief, p. 17-20.
[63] PG&E's Opening Brief, pp. 17-20 to 17-21.
[64] Dynegy's Opening Brief, pp. 24-27.

contribution of Moss Landing Units 1 & 2 to local transmission revenue requirements to a small fraction of previous levels. The revenue shortfall is created by the 88 cent per Dth differential between Backbone-level and All Other Customers rates, not by proposed mechanisms to give Moss Landing Units 1 & 2 and others a chance to compete in electricity markets and consequently to continue to make significant contributions to the local transmission revenue requirement.

17.2.5.E.7 Response to Arguments Against Separate Local Transmission EG Class

PG&E offers two rote arguments in opposition to Dynegy's suggestion that the Commission should create a separate rate class for EG customers served by the local transmission system.[65]

First, PG&E argues that a new EG class could result in a shortfall in the local transmission revenue requirement. As noted above, this argument fails to recognize that PG&E's proposed rates and rate structure, if adopted by the Commission, will result in a drastically reduced contribution to the local transmission revenue requirement, even at the high rates PG&E proposes. Dynegy's proposals, including the proposal for a separate local transmission EG class, are designed to provide these EG customers a reasonable chance to compete in the CAISO's electricity markets, which, if successful, would result in a greater contribution to the local transmission revenue requirement, not a shortfall.

Second, PG&E contends that the proposal is not sufficiently developed. As discussed above, Dynegy does not have access to the resources and information that PG&E does, but that does not mean that the Commission should not consider Dynegy's proposal and order

[65] PG&E's Opening Brief, p. 17-21.

implementation of that proposal through later filings, *i.e.*, the same process the Commission followed when it changed the rate structure for Schedule G-EG.

17.2.5.E.8 Response to Arguments Against Dynegy's Purchase or Virtual Purchase of Capacity of Line 301-G and a Potential Long-Term Contract

As discussed above, PG&E's primary objection to the idea that Dynegy would purchase (or enter into a commercial arrangement that mimics a purchase without a transfer of title—a virtual purchase) a portion of the capacity of Line 301-G was that it would complicate the operation of the gas transmission system. However, PG&E's witness acknowledged that SMUD's purchase of part of the capacity of PG&E's Lines 300 and 401 (which exactly parallels on the backbone system Dynegy's proposal for Line 301-G) has not created any operational problems.

Calpine thinks that a purchase or virtual purchase of capacity on Line 301-G could be acceptable if the price Dynegy paid for the capacity was "reasonable" and if PG&E agreed to sell.[66] Calpine's view of a reasonable price, however, is based on the high end of cost estimates for a *new* pipeline. The capacity Dynegy would be purchasing, however, is from a 49-year old pipeline.[67] A reasonable price for capacity from Line 301-G would reflect the age and condition of the facility.

Calpine similarly thinks a long-term contract for gas transportation service could be acceptable if Dynegy demonstrated that "it would be feasible for it to acquire the necessary rights-of-way, obtain needed permits, and build such a lateral." Depending on the level of proof of feasibility that Calpine contemplates, Calpine's position seems to be designed to ensure that a long-term contract is not a reasonable possibility.

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[66] Calpine's Opening Brief, p. 79.
[67] Exh. Dynegy-6, PG&E's Answer to Question 3.

17.2.5.F PG&E's and Calpine's References to Deleted Passages of the Commission's Decisions Should Be Ignored

Both PG&E's and Calpine's briefs include references to portions of D.03-12-061 that the Commission deleted when it modified D.03-12-061 in D.04-05-061, and Calpine's brief includes quotations from the deleted text. In D.04-05-061, the Commission denied rehearing of D.03-12-061 but made extensive modifications to that decision. In particular, the Commission deleted its discussion of its reasons for adopting the bifurcated rate structure for electric generators and substituted a new discussion with somewhat different reasoning.

Obviously, text that the Commission has explicitly deleted has no relevance and should not be cited in support of positions taken on issues in this proceeding. Dynegy is not suggesting that PG&E and Calpine intentionally cited or quoted deleted text. PG&E and Calpine may not have been aware that the Commission had amended D.03-12-061 (neither cites D.04-05-061 in its brief), or they may have been confused by the way the Commission indicated its deletion. In Ordering Paragraph 1.a of D.04-05-061, the Commission directed the following modification: "On pages 347 through 353 delete the entire text under the heading '**a. Discussion**' and replace it with the following . . . ."[68] The problem is that the indicated page references were to the printed version of D.03-12-061 that was served on the parties. The pagination of the pdf version of the decision that appears on the Commission's website, however, is different. The deletions that the Commission referred to appear on pages 364-370 of the website version, rather than pages 347-353 as indicated in D.04-05-061. This discrepancy is apparent from the fact that there are no headings, much less a heading labelled "a. Discussion," on page 347 of the website version, and page 353 is in the middle of a passage, not at its end.[69]

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[68] D.04-05-061, p. 14 (bold in original).
[69] Dynegy's references to D.03-12-061 in this brief use the pagination of the website version.

If PG&E and Calpine were aware that D.03-12-061 had been modified, they may have been misled by the reference to the deleted section as spanning pages 347 to 353. The corresponding pages on the website version are pages 364 to 370, so in referring to those pages, PG&E and Calpine may have mistakenly assumed that the references were beyond the deleted passage.

In any event, references to text that the Commission has explicitly deleted are inappropriate, and the Commission should disregard following passages of PG&E's and Calpine's briefs:

PG&E:

- Footnote 108 on page 17-16.
- Footnote 112 on page 17-17 and related text.

Calpine:

- The first full paragraph on page 38, which begins, "In Decision 03-12-061," and footnotes 150, 151, and 152.
- The second and third sentences of the second full paragraph on page 43, which begins, "That some EG customers . . . ." and footnote 162.

17.2.6 Commercial Energy's Proposal to Modify the Noncore Customer Class Definition

18. Core Gas Supply

19. Proposals for Programs Directed Toward Small and Medium Sized Businesses

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The challenges facing PG&E and the Commission in the wake of the San Bruno explosion require the Commission to resolve some novel and complicated issues in this proceeding. Dynegy hopes that its briefs and testimony aid the Commission in understanding and resolving some of those issues. Dynegy respectfully urges the Commission to carefully consider the points made in Dynegy's briefs and testimony and to adopt Dynegy's recommendations on rate design for Schedule G-EG.

Respectfully submitted May 20, 2015 at San Francisco, California.

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